



Abertay University

ABERTAY UNIVERSITY DUNDEE, SCOTLAND (U.K.)

**APPLICATION OF META-ANALYTICAL PROBABILISTIC
APPROACH FOR RELIABILITY BENEFITS REFLECTIVE
OPTIMAL TRANSMISSION COSTING – THE CASE OF INDIA**

By

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**A Thesis submitted in partial fulfilment
of the requirements for the Degree of
Doctor of Philosophy in Electrical Engineering**

November 2015

DECLARATION

I hereby declare that I am the author of this thesis, and unless otherwise stated, all references cited have been consulted by me. The work, of which the thesis is a record, has been carried out by me and it has not been previously accepted for a higher degree. This work has been carried out under the supervision of Dr Cüneyt Süheyl Özveren and Dr Daniel Gilmour.

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ABSTRACT

In the deregulated Power markets it is necessary to have a appropriate Transmission Pricing methodology that also takes into account “Congestion and Reliability”, in order to ensure an economically viable, equitable, and congestion free power transfer capability, with high reliability and security. This thesis presents results of research conducted on the development of a Decision Making Framework (DMF) of concepts and data analytic and modelling methods for the Reliability benefits Reflective Optimal “*cost evaluation for the calculation of Transmission Cost*” for composite power systems, using probabilistic methods.

The methodology within the DMF devised and reported in this thesis, utilises a full AC Newton-Raphson load flow and a Monte-Carlo approach to determine, Reliability Indices which are then used for the proposed *Meta-Analytical Probabilistic Approach* (MAPA) for the evaluation and calculation of the Reliability benefit Reflective Optimal Transmission Cost (ROTC), of a transmission system. This DMF includes methods for transmission line embedded cost allocation among transmission transactions, accounting for line capacity-use as well as congestion costing that can be used for pricing using application of Power Transfer Distribution Factor (PTDF) as well as Bialek’s method to determine a methodology which consists of a series of methods and procedures as explained in detail in the thesis for the proposed MAPA for ROTC.

The MAPA utilises the Bus Data, Generator Data, Line Data, Reliability Data and Customer Damage Function (CDF) Data for the evaluation of Congestion, Transmission and Reliability costing studies using proposed application of PTDF and other established/proven methods which are then compared, analysed and selected according to the area/state requirements and then integrated to develop ROTC.

Case studies involving standard 7-Bus, IEEE 30-Bus and 146-Bus Indian utility test systems are conducted and reported throughout in the relevant sections of the dissertation. There are close correlation between results obtained through proposed application of PTDF method with the Bialek’s and different MW-Mile methods.

The novel contributions of this research work are: firstly the application of PTDF method developed for determination of Transmission and Congestion costing, which are further compared with other proved methods. The viability of developed method is explained in the methodology, discussion and conclusion chapters. Secondly the development of comprehensive DMF which helps the decision makers to analyse and decide the selection of a costing approaches according to their requirements. As in the DMF all the costing approaches have been integrated to achieve ROTC. Thirdly the composite methodology for calculating ROTC has been formed into suits of algorithms and MATLAB programs for each part of the DMF, which are further described in the methodology section.

Finally the dissertation concludes with suggestions for Future work.

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In the words of Colin Powell - “A dream doesn’t become reality through magic; it takes sweat, determination and hard work.”

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Dundee, 2015

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LIST OF ABBREVIATIONS

AC	-	Alternating Current
ACPTDF	-	Alternating Current Power Transfer Distribution Factors
ARR	-	Aggregate Revenue Requirement
ASAI	-	Average Service Availability Index
ATC	-	Available Transfer Capability
ANN	-	Artificial Neural Network
BMC	-	Bus Marginal Cost
CAGR	-	Compound Annual Growth Rate
CAIDI	-	Customer Average Interruption Duration Index
CBM	-	Capacity Benefit Margin
CCDF	-	Composite Customer Damage Function
CDC	-	Customer Damage Cost
CDF	-	Customer Damage Function
CEA	-	Central Electricity Authority
CERC	-	Central Electricity Regulatory Commission
CIC	-	Customer Interruption Cost
C/Km	-	Circuits per Kilometre
COPT	-	Capacity Outage Probability Table
CPF	-	Continuation Power Flow
CPI	-	Cost Per Interruption
CTU	-	Central Transmission Utility
DC	-	Direct Current
DMF	-	Decision Making Framework
EBE	-	Equivalent Bilateral Exchange

ECOST	-	Expected Customer Damage Cost
EDNS	-	Expected Demand Not Supplied
EENS	-	Expected Energy Not Supplied
EIC	-	Expected Interruption Cost
ENS	-	Energy Not Served
ERCOT	-	Electric Reliability Council of Texas
ESI	-	Electricity Supply Industry
ETAP	-	Electrical Transient Analyser Program
EUE	-	Expected Unserved Energy
FACTS	-	Flexible Alternating Current Transmission System
FERC	-	Federal Energy Regulatory Commission
FLC	-	Frequency of Load Curtailment
FOR	-	Forced Outage Rate
FTR's	-	Financial Transmission Rights
FYP	-	Five Year Plan
GA	-	Genetic Algorithm
GAPP	-	General Agreement on Parallel Paths
GDP	-	Gross Domestic Product
GGDF	-	Generalised Generation Distribution Factors
GLDF	-	Generalised Load Distribution Factors
GLODF	-	Generalised Load Outage Distribution Factors
GOQDF	-	Generation Outage Reactive Power Distribution Factor
GOVDF	-	Generation Outage Voltage Distribution Factor
GSDF	-	Generalised Shift Distribution Factors
GSF	-	Generation Shift Factor
GW	-	GigaWatt

HVDC	-	High Voltage Direct Current
ICDF	-	Individual sector Customer Damage Function
IEA	-	International Energy Agency
IEAR	-	Interrupted Energy Assessment Rate
IEEE	-	Institute of Electrical and Electronics Engineers
IIT's	-	Indian Institute of Technology
IPPs	-	Independent Power Producers
ISF	-	Injection Shift Factors
ISOs	-	Independent System Operators
LDC	-	Load Duration Curve
LMP	-	Locational Marginal Pricing
LODF	-	Line Outage Distribution Factors
LOEE	-	Loss-of-Energy Expectation
LOEP	-	Loss of Energy Probability
LOLE	-	Loss-of-Load Expectation
LOLP	-	Loss of Load Probability
LOQDF	-	Line Outage Voltage Reactive Power Distribution Factor
LOVDF	-	Line Outage Voltage Distribution Factor
LRIC	-	Long-Run Incremental Cost
LRMC	-	Long-Run Marginal Cost
MAPA	-	Meta-Analytical Probabilistic Approach
MATLAB	-	Matrix Laboratory
MC	-	Monte Carlo
MC-VRT	-	Monte Carlo –Variance Reduction Techniques
MES	-	Minimum Efficient Scale
MLC	-	Minimum Load Curtailment

MU	-	Millions of Units
MVA	-	Mega Volt Ampere
MW	-	Mega Watt
NEP	-	National Electricity Policy
NERC	-	North American Electric Reliability Corporation
NPP	-	National Power Plan
N-R	-	Newton-Raphson
OPF	-	Optimal Power Flow
PA	-	Power Auditing
PGCIL	-	Power grid Corporation of India Limited
PIDF	-	Power to Current magnitude Distribution Factor
PLC	-	Probability of Load Curtailment
PoC	-	Point of Connection
PQ&R	-	Power Quality and Reliability
PSADD	-	Power System Application Data Dictionary
PSP	-	Proportional Sharing Principle
PTDF	-	Power Transfer Distribution Factors
RC	-	Relief Cost
RNC	-	Revenue Not Collected
ROTC	-	Reliability benefit reflective Optimal Transmission Cost
RPC's	-	Regional Power Committee
SAIDI	-	System Average Interruption Duration Index
SAIFI	-	System Average Interruption Frequency Index
SCAE	-	Security Constrained Adequacy Evaluation
SCDF	-	Sector Customer Damage Function
SEB	-	State Electricity Board

SERC	-	State Electricity Regulatory Commissions
SQP	-	Sequential Quadratic Programming
SRIC	-	Short-Run Incremental Cost
SRMC	-	Short-Run Marginal Cost
T&D	-	Transmission and Distribution
TBPF	-	Transaction Based Power Flow
TC	-	Transmission Charges
TCC	-	Total Congestion Cost
T&D	-	Transmission and Distribution
TERI	-	The Energy and Resource Institute
TNUoS	-	Transmission Network Use of System charges
TRM	-	Transmission Reliability Margin
TTC	-	Total Transfer Capability
TTF	-	Time To Failure
TTR	-	Time To Repair
TTS	-	Time To Switch
TWh	-	Tera-Watt Hours
UC	-	Uniform Charge
UI	-	Unscheduled Interchanges
VRT	-	Variance Reduction Technique
ZC	-	Zonal Charge

PART-1

- 1. INTRODUCTION**
- 2. LITERATURE REVIEW**

CHAPTER- 1

1.1 AIM

The main stimulus for the present investigations has been the conceptual evolutions in Electricity Trading, Open Access, and Competitive Electricity Market Structures that are currently being operated. As in some parts of this evolution there is a nascent need for a comprehensive framework that will *adequately price reliability and security that will help mitigate and resolve the system congestion, which is effective and equitable while guaranteeing economically viable and attractive costing and revenue recovery*. Although the need is global and generic where such reforms are taking place, the reported investigations have been conducted in the context of the Indian Electricity Supply Industry (ESI). However the results and implications are transferable to any country or regional ESI and hence the research emphasizes the DMF and ROTC methodology.

In the present competitive scenario, there is an essential requirement for a systematically reliable and planned Power System, for economical generation, optimal customer costing as well as the quality and reliability assurance of power supplied.

Therefore the main purpose of this research was to develop concepts and techniques in the ROTC (Reliability benefit Reflective Optimal Transmission Cost) evaluation and calculation for composite power systems using the proposed MAPA (Meta-Analytical Probabilistic Approach) methods. This research was aimed at devising a DMF (Decision Making Framework) and a methodology that can be used to include the Reliability Benefits and achieve optimal cost allocation on an equitable and

practical basis and hence can be utilised for socio- economically viable Transmission Pricing.

The objectives to achieve the above stated aim were to devise a DMF and a ROTC methodology that would be reliability benefit reflective and utilise an efficient Congestion costing approach.

The main parts of this DMF and ROTC methodology can be outlined as follows;

1) *Transmission costing part; calculation of the Transmission Costing:*

The DMF and the methodology to include algorithms and programmes based on these algorithms to define;

- a) a novel and enhanced application of PTDF method,
- b) a DMF utilising different costing and cost allocation methods, listed below, for verification and considering alternatives in the decision making process for ROTC.
 - i) Bialek's method
 - ii) Three MW-Mile methods
 - (1) Reverse MW-Mile method
 - (2) Dominant MW-Mile method
 - (3) Absolute MW-Mile method

2) *Congestion Costing part; Calculation of the Congestion Costing:*

In this part a comparison between the newly developed application of PTDF method and Bialek's method was made for proving the viability of the proposed method and improving the decision making process.

3) *Reliability Worth Indices part; Evaluation and Calculation of Reliability Worth Indices:*

This part utilises Probabilistic methods i.e. Monte Carlo simulation method in which Variance reduction Techniques such as

- a) Simple Sampling
- b) Importance Sampling and
- c) Time sequential approach (were used for estimation of)
 - i) EENS (Expected Energy Not Supplied)
 - ii) ECOST (Expected Customer Damage Cost) &
 - iii) IEAR (Interrupted Energy Assessment Rate) index

4) *Integration part; Integration of all costs*

In this part which constitutes the final phase, all costs obtained from transmission, congestion and reliability worth indices are combined for achieving the ROTC.

The following chapters and relevant sections will: report on the results of the comprehensive literature review on the subject detailing the outline of the recently reported methodologies that are widely discussed and accepted in the literature; detail the methodology for implementing ROTC using the devised DMF; shows the results of the case studies for discussion, verification and comparison with published work; give conclusions that can be drawn from the investigations and make suggestions for future work. The detailed results, codes and data used for the investigations are provided in the relevant appendices.

The main analytical engine used in this approach is a full Newton-Raphson AC Load Flow that is used to determine the line capacity-use as determined by the amount of power transmitted. This approach will also allow the extension of the ROTC methodology to include the effects of reactive power in future work.

1.2 RATIONALE

India is one of the fastest – growing economies of the world with globalisation diffusing into almost every sector in the country, including the power sector. This requires a series of structural and operational changes to reform the power sector to meet the growing economy demands within the resource, finance and environmental constraints of the country. To date the reforms have mainly been concentrating on introducing competition to different parts and setting up regulatory reforms and process bodies and establishing appropriate funding mechanisms.

State Regulatory Commissions (SERCs) have been set up to oversee and guide the reforms and the process. SERCs are charged with the role of devising and rationalizing the tariffs, protecting customer interests, ensuring improved customer service, and setting the delivery standards as well as guiding the open access process at the state level.

An impromptu Power Transmission System results in over generation of power (over investment) or unserved demand. The system's ability to supply adequate electrical energy to the consumers depends upon adequate reliability levels of the Power System as the loss of power supply has significant impact on energy suppliers and socio-economically on consumers. So it is vital to maintain adequate levels of power system reliability for system planning and operations.

Simple incremental increases of generation capacity and transmission network, installation and expansion, are assumed to be sufficient to satisfy the load demand but, in countries like India where the demand increases approximately 10% every year with huge financial constraints in investments, it becomes more essential to

examine reliability and security critically along with the rate of incremental load change.

The Indian Power Sector has expanded enormously post independence. Since 1996, deregulation in each section of the power system has been introduced, opening the electrical market for public and private participation, changing the Electrical supply Industry (ESI) from centrally planned to regionally distributed system planning and operation, responsible for security and reliability with SERC oversight.

With the growing need for more power and trade, the reliability demand has increased at the component and system level with the context of providing quality and reliable power to all. The awareness and importance of reliability compels ESI to invest more, as well as consumers being willing to pay extra, realizing the importance of reliable power supply.

1.3 THESIS OUTLINE/ORGANISATION

The organisation of this thesis research work is as follows.

In chapter 2, the literature review consisting of relevant theories, principles and concepts required for supporting the Available Transfer Capability, Congestion Management, Transmission costing, Reliability of Power System and the Indian Power System Scenario is presented. All of the above stated topics related to power system are explained in detail concerning the previous findings and the research gap.

Chapter 3 is mainly concerned with the methodology adopted to estimate transmission costing using reliability worth along with congestion in the transmission system. In this chapter the main contribution of this research work in the field of

Power System Transmission costing and Power System Reliability have also been discussed.

Load flow is the back bone of power system analysis and any evaluation in power systems. In Chapter 4 the Load Flow is explained along with its necessity and requirement in power system. The results of load flow using Newton-Raphson Load Flow method is shown for 7-Bus (M, H 2015), IEEE 30-Bus (Gnanadass 2015) and Indian Utility 146-Bus systems (TamilnaduElectricityBoard 2015) for constrained and unconstrained cases, which are used for further calculation of costing in the Transmission System.

In Chapter 5 the Transmission Costing methods and its theory is discussed along with the methods used for calculating Transmission costing. Also the results of the calculation were conducted using MW-Mile methods, Bialek's method, the proposed application of PTDF method and their comparison with each other for 7-Bus, IEEE 30-Bus and Indian Utility 146-Bus systems.

Chapter 6 is solely concerned with the Congestion Costing theory, methods and its estimation using Bialek's and the proposed application of PTDF methods. The congestion cost is calculated using these two methods for 7-Bus, IEEE 30-Bus and Indian Utility 146-Bus system, they are compared and explained for their accuracy and importance.

In Chapter 7, Probabilistic evaluation of Reliability worth is undertaken. The theory concerning reliability worth along with methods used to find reliability worth and reliability data used are discussed in this chapter. The MC-VRT (Monte Carlo – Variance Reduction Techniques) is used to find the worth of reliability.

Chapter 8 is devoted to the general discussion of the results evaluated during the research and also the final result of Transmission costing using reliability benefits and congestion is calculated and discussed.

In Chapter 9 concluding remarks and future work recommendations are presented. This chapter summarises the thesis as well as briefly discussing the results and contribution from each chapter.

CHAPTER – 2

LITERATURE REVIEW

INTRODUCTION

**INDIAN POWER SECTOR
OVERVIEW**

TRANSMISSION PRICING SCENARIO IN INDIA

**AVAILABLE TRANSFER
CAPABILITY OF
TRANSMISSION SYSTEM**

**SIGNIFICANCE OF ATC IN TRANSMISSION SYSTEM
RELIABILITY**

ATC EVALUATION METHODS

**TOTAL TRANSFER CAPABILITY OF TRANSMISSION
SYSTEM**

**CONGESTION
IN TRANSMISSION
SYSTEM**

OVERVIEW

CONGESTION MANAGEMENT GENERAL PROCEDURE

MANAGEMENT OF TRANSMISSION CONGESTION

**DISTRIBUTION FACTORS
FOR TRANSMISSION LINE**

POST LINE OUTAGE DISTRIBUTION FACTORS

POWER TRANSFER DISTRIBUTION FACTORS (PTDF)

SIGNIFICANCE OF PTDF IN TRANSMISSION COSTING

FLOW/TRANSFER

A.C. POWER TRANSFER DISTRIBUTION FACTORS (ACPTDF)

SENSITIVITY ANALYSIS

LINE OUTAGE DISTRIBUTION FACTOR (LODF)

**TRANSMISSION PRICING
REVIEW**

IMPORTANCE OF TRANSMISSION PRICING

**METHODS REPORTED IN THE LITERATURE FOR
TRANSMISSION PRICING**

**THE TRANSMISSION PRICING METHODS EVALUATED IN
DETAIL**

**SIGNIFICANCE OF POWER FLOW TRACING IN TRANSMISSION
PRICING STUDIES**

**RELIABILITY
EVALUATION OF
ELECTRIC POWER
SYSTEM**

OVERVIEW

**CALCULATION OF RELIABILITY , ADEQUACY & SECURITY
OF SYSTEM**

MODELLING METHODS FOR BULK POWER SYSTEM

RELIABILITY ASSESSMENT METHODS

REVIEW OF RELIABILITY INDICES

CLASSIFICATION OF RELIABILITY INDICES

OUTAGE COST STUDY

SUMMARY

LITERATURE REVIEW

2.1 INTRODUCTION

This chapter provides a critical review of the previous research undertaken in areas relevant to the underlying theme of Congestion Costing, Transmission Costing and Reliability Evaluation. The key aspects which are reviewed include overall structure of Indian Electrical Industry, Available Transfer Capability, Congestion Management, Distribution Factors, Transmission Costing, Reliability Evaluation and Power Outage Study. The review of literature concludes with the discussion of the gaps present in today's knowledge which needs further investigation and also the summary of the key findings in these relevant areas.

2.2 INDIAN POWER SECTOR OVERVIEW

All the Power companies in the world have either chosen or are choosing deregulation of their Power Systems. The first countries to implement deregulation in electricity market were Argentina and Chile. India's progress towards deregulation is already initiated and competition at generation level is created by inviting private Independent Power Producers (IPPs). In some states of India, the power system is divided among three separate entities i .e. Generation, Transmission and Distribution (Kumar, Das et al. 2013)

After independence India has suffered from the increasing demand for electrical power, frequent power cuts, shortage of natural resources and the concern for global warming, which hinders the overall development of the country. The power sector

has suffered slow growth due to financial mismanagement and poor regulation. (Sharma 2014)

In 1991 first reform started by introducing Independent Power Producers (IPP). This was because of ever increasing demand and the inability of the State Electricity Board (SEB) to deal with technical and financial problems. As a result, an amendment was made in the Indian Electricity Act, 1910 and the Electricity (Supply) Act 1949, so as to invite private investors in generation. According to the World Bank power sector reforms, Orissa is one of the states of India which unbundled its SEB into Generation, Transmission and Distribution in 1996. In order to manage the uneven distribution of power stations in the region, the Regional Power Grid was established. The purpose of the Regional Power Grid is to control the power transfer by supplying the regions having insufficient power supply considering loads and demands. India, as a whole is divided in five transmission regions as shown in Figure 2.1 i.e. Northern Region, North Eastern Region, Eastern Region, Western Region and Southern Region and all the five regions are inter-connected for import and export of electrical power. The central transmission company is the Power Grid Corporation of India Limited (PGCIL) which controls 80% of regional transmission. Till now there is a dominant government control in the transmission of power and the involvement of private sector is minimal but 'The Electricity Act 2003' invites and encourages the private sectors participation to overcome the financial and supply constraints. (Choudhry 2011, Besant-Jones 2006)



Figure 2.1: Regional Power Grids of India

Source: (CEA 2015)

2.2.1 PRESENT GENERATING CAPACITY AND ITS UTILIZATION

According to India's financial and demographic development, it is expected that power utilization will improve from an evaluated 724.18 Terawatt Hours (TWh) in 2011 to 1,398.61TWh in 2021 (India Power Report 2012) .

The nation's twelfth Five Year Plan figures vital interest in India's energy demands, which is expected to grow by 6% every annum and a power limit to be extended by 100 GigaWatt (GW) (20GW every annum).

In order to cut down the dependence on electricity import, India is looking towards renewable and nuclear sources, but it is still facing problems to achieve its target in

recent years. The reason behind this is the reluctance of State government to give support and provide space for massive infrastructure. The Indian financial sector also obstructs the funding of those installations. Apart from this, administrative straightforwardness, life span and certainty in the power sector remain deficient.

Indian utilities in 2012 have not performed well due to lack of adequate coal supply. But in February 2012 Coal India has entered into a long term agreement with the Indian utilities to ease the problem for a short while.

Indian government is planning to increase the import duty on electrical generation equipment which can raise the cost for Indian private independent power producers (IPPs), but somehow the country's internal electrical generation equipment manufacturers will get some cost competition benefits.

In 2012 India has achieved a seven fold increase in funding for solar projects which is almost equal to the amount of \$US4.6bn invested in the Indian wind sector in 2011.

India has workable hydro potential of about 84,000MW at a 60% load factor and an extra 6,780MW from small hydro schemes and it ranks 5th in the world ranking in hydro potential.

With the newly installed wind power capacity of more than 16 GW in December 2011, India works more actively in the field of renewable energy generation.

Due to the shortage of a reliable generating capacity and more power wastage, demand goes up as compared to the available electrical power. According to the report of the Central Electricity Authority in 2011 the total demand was 10% above the supply and the peak demand is 13% above the supply.

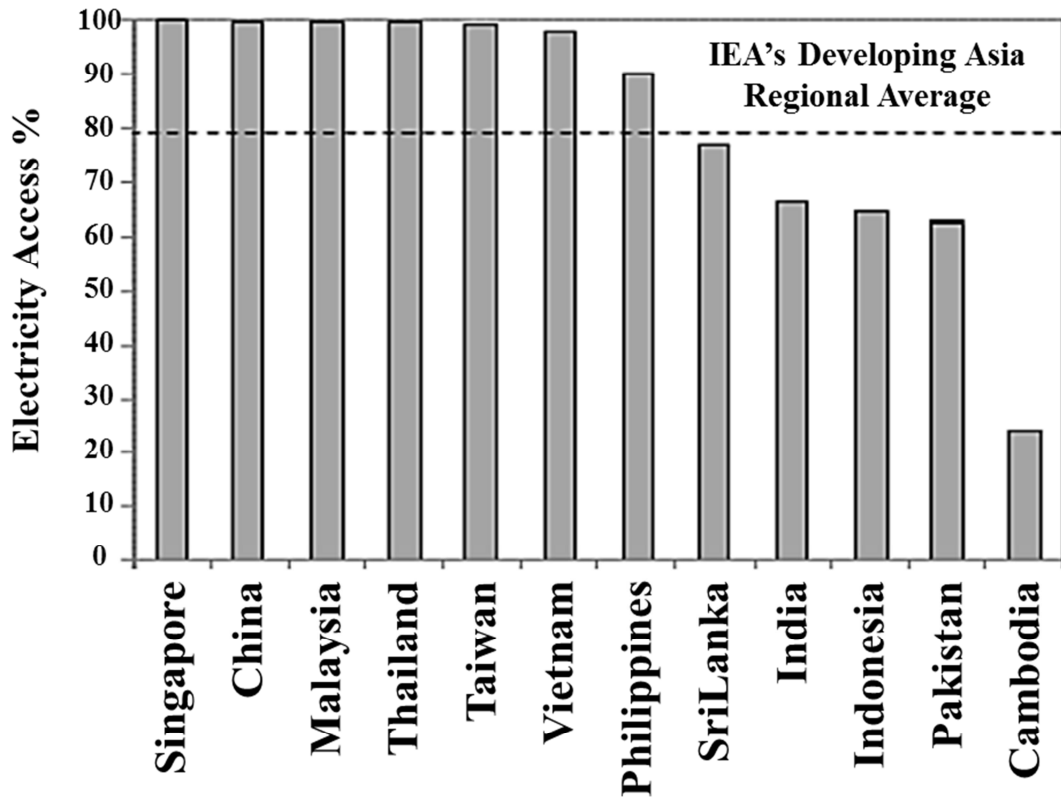


Figure 2.2: Increasing Electrification Rates (Electricity Access (%) In Developing Asia in 2009)

Source: (India Power Report 2012)

From the Figure 2.2 it can be seen that until 2012 India's electrification rate was slightly less than the regional average.

It has been reported that over 300 Million citizens in India still had no access to electricity in 2011 and the annual power loss was estimated up to 24%.

The Indian government has failed to meet the targets to install more generating capacities because of poor project management and issues with procurement of equipment.

Some of the Hydroelectric projects in India are sluggish because of ecological, environmental and rehabilitation controversies and also due to public protest.

It can be seen from the Figure 2.3 that Indian quality of power supply is 3.1 which is half of the quality achieved by different countries on the scale of 7.

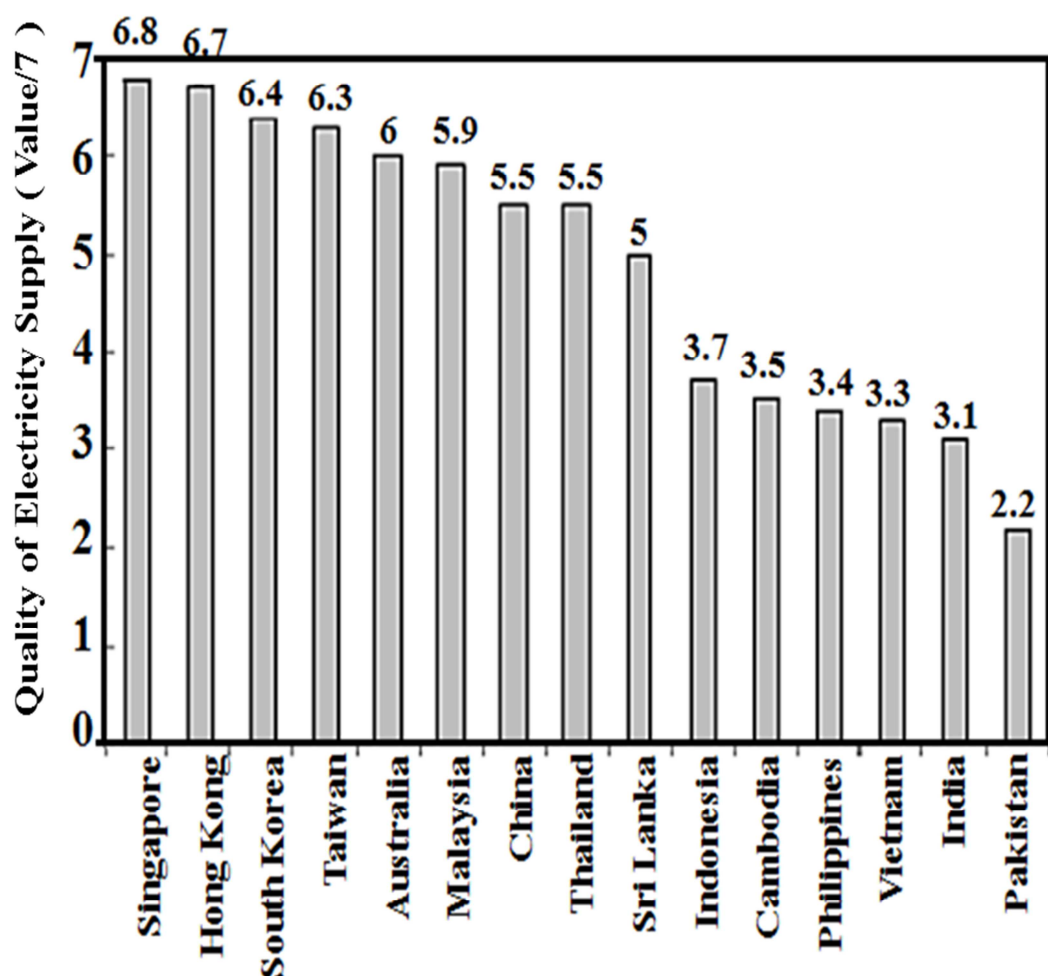


Figure 2.3: Improving Quality of Supply (Quality of Electricity Supply (Value/7))

Source: (India Power Report 2012)

India needs an additional 75 GW or more from now until 2017 in order to achieve the target of 9 % GDP growth.

During the period of 2012 to 2021 the expected annual average increase in power generation is 6.68 % i.e. 1,803 TWh in which thermal power plants will still be the back bone of the Indian power sector, covering 52 % of the overall generation. World Nuclear Association data shows that 20,000 MW of nuclear capacity will be online in India by 2020. By 2020 India is targeting for 15% renewable energy which comes under the National action Plan for climate change.

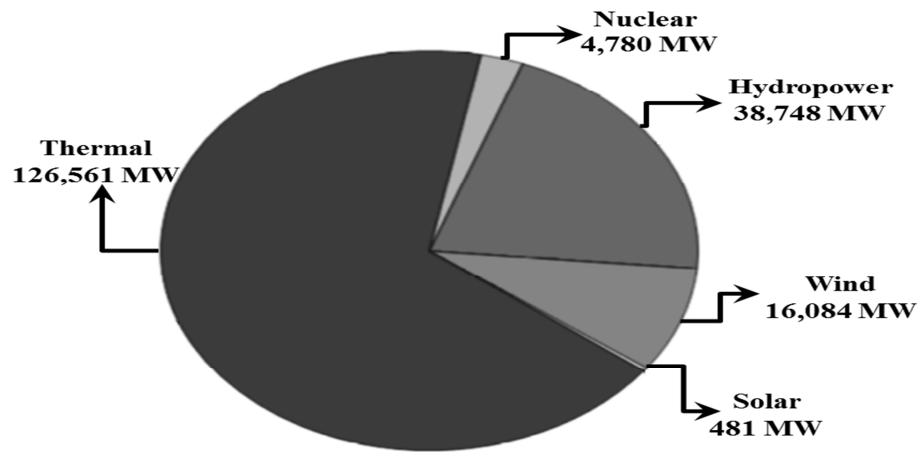


Figure 2.4: Total Electrical Power Capacity (MW) of India, in 2011

Source: (India Power Report 2012)

From the Figure 2.4 it can be seen that India's total capacity in 2011 was 186654 MW. India's overall length of Transmission and Distribution networks is 6.5 Million Km and the annual power loss in that system is calculated up to 24%. In some states, it is more than 50% and the national average comes out to be 25% power loss on the network as compared to international best practices of 4 per cent losses in Transmission And Distribution (T&D) provided by CEA (Central Electricity Authority) annual report 2012 (Sharma 2014).

Power grid was the controller for the installation of new transmission network but now this sector has been deregulated and private investors and companies are invited to bid and construct the transmission system expansion projects (Choudhry 2011).

All India power supply position in 2014 is shown in the Table 2.1 below where MU is the millions of units supplied (Pujara, Chikhal et al. 2014).

Central Electricity Regulatory Commission (CERC) asked CEA to form a National Reliability Council by 21-02-2014, which will take care of the better reliability in all the transmission corridor of the national grid and for this purpose, the representatives from IIT's, CTU (Central Transmission Utility), CEA and RPC's (Regional Power

Committee) / State Representatives were to be invited for the approval of computation methodology to estimate Total Transfer Capability (TTC) (CEA 2015).

Table 2.1: All India power supply position in 2014

Region	Power			
	Requirement	Availability	Surplus(+) /Deficit(-)	(%)
	(MU)	(MU)	(MU)	
Northern	319885	301418	-18467	-5.8
Western	286752	283396	-3356	-1.2
Southern	309840	250583	-59257	-19.1
Eastern	119632	131880	12248	10.2
North-Eastern	12424	11024	-1400	-11.3
All India	1048533	978301	-70232	-6.7

2.2.2 TRANSMISSION PRICING SCENERIO IN INDIA

2.2.2.1 Recent Development in Transmission Pricing Schemes

According to CERC (2010) report, the efficient pricing scheme for charging electricity should contain the marginal cost of utilization of the electrical services provided. This can be estimated considering marginal or average utilization of services. Pricing transmission services in terms of average and marginal utilisation is known as Average Participation Method and Marginal Participation Method respectively. Any of the power tracing algorithms can be used to determine the transmission charges using Average Participation Method i.e. it can be evaluated using flow based method. And for Marginal participation method, Incremental Pricing Methods can be used for calculating transmission prices. Combination of these two methods can be used to determine overall transmission charges where Average Participation Method will be utilised for selecting the swing bus and Marginal Participation Method is used for estimating the charges including transmission price and losses. Soonee, Barpanda et al. (2013), Choudhry (2011),

Modi (2011) have further explained in their reports that this hybrid method is called Point of Connection (PoC) (Roy, Abhyankar et al. 2006) based transmission pricing method. For a zone the PoC method is the proportionate sum of Uniform charge and zonal charge i.e. PoC Charge (PoC) = $m * \text{Uniform Charge (UC)} + n * \text{Zonal Charge (ZC)}$ (hybrid method) (2.1)

Where m and n are the constants specified in the regulation which is 0.50 for initial two year set by commission and the uniform charge can be calculated as,

$$\text{UC} = \text{Total ARR} / (\text{Sum of Approved Injection} + \text{Sum of Approved Withdrawal})$$

Roy, Abhyankar et al. (2006) have calculated the PoC rates for the regional states of western India and concluded that the implementation is easier for power exchange between regions and short term bilateral exchanges, in order to recover transmission system usage cost.

CERC, which is central power regulator of India, has disclosed a new pricing method for inter-state transmission of power i.e. point of connection method which is used for sharing inter-state transmission cost (News 2010). Under the previous method of Postage Stamp they were charged a uniform cost for inter-state transmission. It has been expected that the new transmission pricing scheme will present lower transmission charges in the long run. This method considers distance and direction of flow of electricity. Its implementation will be better for electricity market integration and will increase open-access and competition.

To date the Postage Stamp Method has been used, due to which all the transmission grid users are paying the same transmission charges and the loss charges are shared among them. But with the new transmission pricing scheme all the charges and the losses will be charged according to the true utilization of the transmission network by

the user. The new method considers distance, peak and off-peak timings of operation for charging.

A review has been undertaken by Kumar, Das et al. (2013) for transmission pricing reforms in India according to which National Electricity Policy (NEP) orders for the transmission tariff framework to be implemented which should consider distance direction and magnitude of power flow. This is to ensure that the transmission network users pay only for the proportion of the transmission system used. The responsibility of DMF development and implementation is given to CERC. The suggestion of CEA for sharing charges is to use a Zonal Postage Stamp Method which will be implemented after in-depth study and discussion. One challenge to be faced in reforming the transmission pricing is that for the short term access the recovery is less and the chances for underutilization of network is possible and for long term contracts there are chances that a short term market which includes power exchange between states is discouraged. So, the percentage of long term and short term margins in the transmission system network utilization need to be decided and implemented. Pricing transmission services is complicated work, whereby industrial experts, economists and academicians are trying to come up with an exact answer as to which pricing method, comparing the present Postage Stamp Method or the distance considering method will be best for setting the future transmission charges. Kumar, Reddy et al. (2010) have conducted an analysis for a 40 bus system in the Eastern region of India using a combination of Postage Stamp Method with three different types of MW-Mile method separately and concluded that the Absolute MW-Mile method along with Postage Stamp Method are more accurate in recovering the cost of transmission system use and also ensures the recovery of used and unused

capacity of transmission network but ignores the counter flow initiated by customers in the transmission line.

Kalra, Saxena et al. (2004) in their discussion suggested that the Postage Stamp and MW-Mile methods are most suitable for Indian conditions, where MW-Mile method is considered as the most transparent and economically effective.

2.2.2.2 Electrical Energy Trading

According to Alagh (2010), for transparent and competitive operation of electrical market a robust trading system is not only desirable but imperative in the emerging economic environment. Short term trading in India has phenomenally increased which leads to very high prices. The major reasons behind it are Unscheduled Interchange (UI) mechanisms, which will have an adverse effect on the trading for state utilities, as the prices have to be high, even though the tariff charges from customers are less. This will result in the financial loss of the state utilities that eventually can be dealt with by supplying big customers through open access which has not been operationalised according to the Electricity Act 2003.

2.2.2.3 Transmission System Losses

Officially the Transmission and Distribution (T&D) losses in India are 23%, which in some states of India can be up to 50% according to TERI (The Energy and Resource Institute). The State Regulation Commission is taking up steps to measure the level of T&D losses as they directly show impact on the transaction of power and also in tariff determination. Transmission losses occur due to the energy dissipated in the components and conductors connected in the transmission network of the voltage category such as 400, 220, 132 or 66 KV. The T&D losses in India has risen from 15% in 1966-67 to 23% in 2014-15 and this rise in losses has become an alarming

issue for the electrical companies. The T&D losses in most of the developed countries are below 10% and India is aiming and working towards reducing the T&D losses roughly down to 10-15%. The reasons for such high T&D losses is that the investment ratio between generation and T&D should be 1:1 but it has been lowered to 1 : 0.45, which results in overloading. Below in Table 2.2, T&D losses for most of the developed and developing countries are shown, from which it can be seen that India's T&D losses are very high i.e. 33%. T&D losses in each state of India as shown in Table 2.3 from which it can be seen that some states are performing well but some states are still struggling to control the T&D losses.

Table 2.2: T&D losses in most of the developed and developing countries

S.No.	Countries	T&D losses (%)
1	India	33
2	U.S.	6-8
3	U.K.	6-8
4	Pakistan	26
5	China	7
6	Russia	12
7	Japan	4
8	Germany	4

Source: (Kumar 2015)

Several other reasons like haphazard growth of sub-transmission system, too many transformation levels, inappropriate management of loads, imperfect reactive compensation and lower grade of equipments used plays an effective role for high T&D losses. After restructuring of the State Electricity Boards (SEB) the T&D losses per state have been increased. So initiatives are required in terms of energy audits, controlling power thefts and reducing barriers for the involvement of the private sector in order to control and reduce the T&D losses (CEA 2015) (Bhalla 2000). The Major Transmission network of India is shown in Figure 2.5 below.

Table 2.3: T&D losses per state in India after restructuring of SEB

State	1991/ 92	1992 /93	1993 /94	1994 /95	1995 /96	1996 /97	1997 /98	1998 /99	1999/ 00
	T&D losses per state in India after restructuring of SEB in %								
Andhra Pradesh	20.3	19.2	19.1	18.9	18.9	33.1	32.5	31.9	31.1
Arunachal Pradesh	28.2	34.9	31.6	31	36	32.6	31	31.1	31.5
Assam	22.7	21	20.8	24.9	26.2	26	30.1	23	30
Bihar	18.3	20.5	19	24.9	25.9	25.3	25.4	39.5	36
Daman & Diu	15.9	0	0	0	0	0	0	0	0
Goa	23.8	20.8	21.8	26.2	28.5	23.5	23.4	29.1	23
Gujrat	23.6	21.1	21.3	20	18.3	21.4	21.7	20.1	18
Haryana	26.8	25.4	25.5	28.5	31.4	32.8	33.4	29.6	29.5
Himachal Pradesh	19.2	18.5	17.3	17.4	17.5	18.4	19.2	18.5	18.1
Jammu & Kashmir	50.1	45.3	47.7	46.9	48.6	50	47.5	43.8	46.5
Karnataka	19.3	18.7	18.6	18.9	18.5	18.9	18.6	17	18.3
Kerala	22.5	21	20.2	20.1	20.1	21.4	17.9	17.5	17
Lakshadweep	17.4	0	0	0	0	0	0	0	0
Madhya Pradesh	25.8	22.2	20.2	20.1	19.5	20.6	19.7	17.8	18.6
Maharashtra	18.6	16.4	15.8	15.3	15.4	17.7	17.1	17.3	17
Manipur	24.4	22.5	22.5	22	21.5	23	21.8	19.7	20
Meghalaya	11.7	12.2	10.7	18.7	17.8	19.5	17.9	18.9	19
Mizoram	34.9	28.1	28	28	27	34.4	25.7	42	43
Nagaland	23.1	32.4	31.6	30.8	30	26.8	29.5	29	28.5
Orissa	25.3	23.5	23.4	23.8	46.9	50.4	46	42	36
Punjab	21.8	18.7	18.5	18.3	18.2	18.9	17.8	17.1	17.7
Rajasthan	23.1	24.5	25.2	25	28.5	25.9	26.5	29.5	22
Sikkim	25.9	21.8	21.5	21.2	21	29.2	20.1	20	19.8
Tamil Nadu	18.4	17.5	17.3	16.9	17	17.2	16.8	16.6	16.5
Tripura	32	30.5	30	30	30	30.1	29.3	28.5	28
Uttar Pradesh	26.1	24.1	23.2	22.6	22.8	25.1	25.5	26.3	22.9
West Bengal	19.7	23.7	22.4	21.1	20.7	20.1	20	19.5	19
All-India (Utilities)	22.8	19.8	20.2	20.3	22.2	24.5	23.9	23.2	22

Source: (Bhalla 2000)

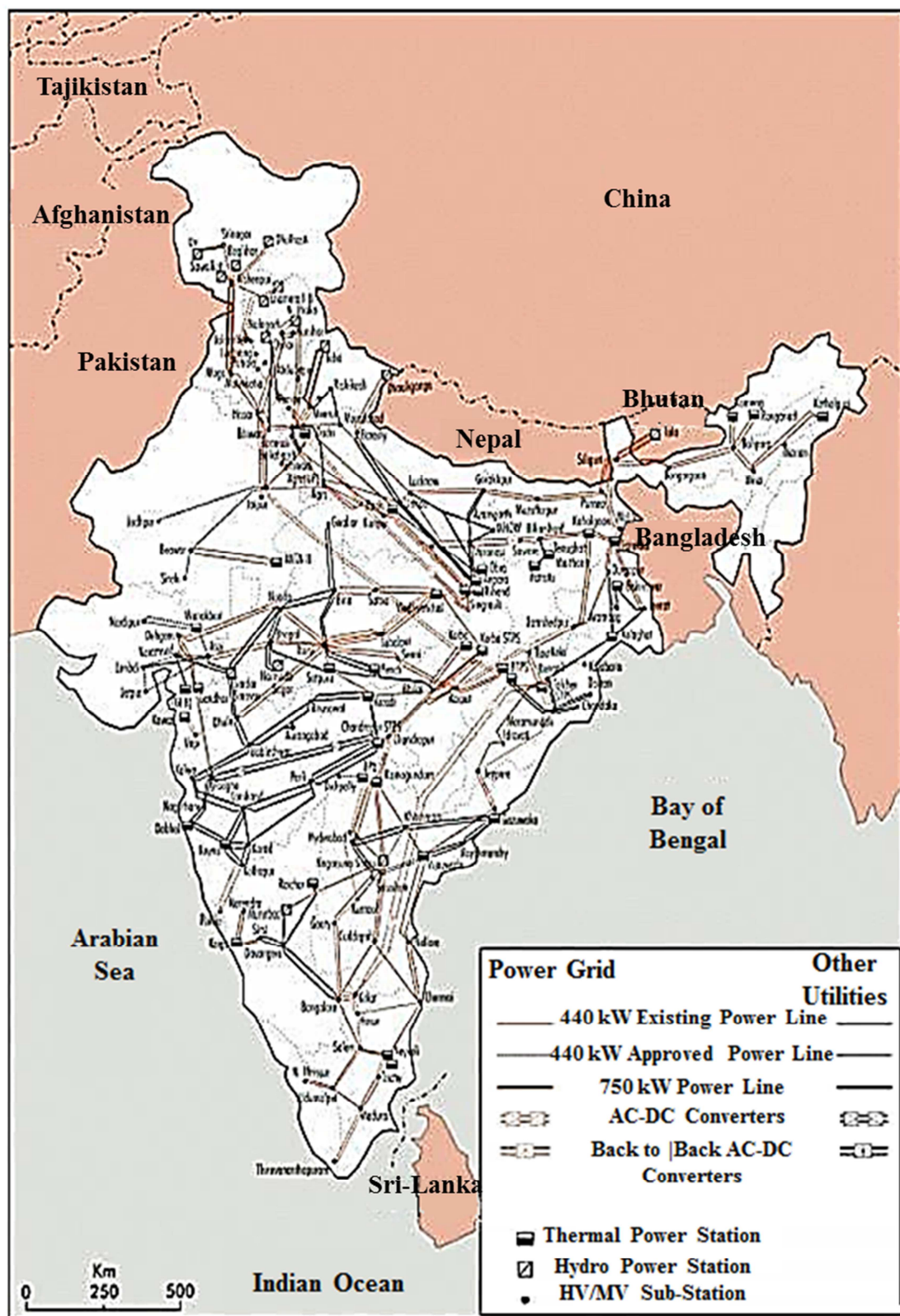


Figure 2.5: Map Showing Major Transmission Networks of India

Source: (GENI 2014)

2.2.2.4 Growth and Development of Transmission System

The Indian government at the end of the 12th five year plan fixed a visionary target to attain power supply for all with reliability, adequacy and quality for which the efficient transmission system plays an important role towards this step.

Table 2.4 shown below gives the total transmission capability of the transmission network until March 2012. India has a total of over 270051 circuits per kilometre (c/Km) of transmission lines as shown in the Table 2.4. In Table 2.5 the projected addition of transmission lines are shown that is 379011 c/Km at the end of the 12th five year plan.

Table 2.4: The total transmission capability of the transmission network in India (March 2012)

Transmission lines	Lines up till Financial Year 12 (anticipated)
765 kV	4644 c/km
HVDC	9452 c/km
400 kV	114979 c/km
230/220 kV	140976 c/km
Total	270051 c/km

Source: (CEA 2015)

Table 2.5: Transmission system in India and projected addition in 12th plan

Transmission lines (AC and HVDC)					
	At the end of 10th Plan	Addition during the first four years of 11th plan (2007-2011)	Expected at the end of 11th plan	Projected addition during the 12th plan	Expected at the end of 12th plan
	c/km	c/km	c/km	c/km	c/km
HVDC Bipole Lines	5872	1580	9452	9440	18892
765 kV	1704	1636	4164	27000	31164
400 kV	75722	26856	114979	38000	152979
220 kV	114629	19780	140976	35000	175976
Total Transmission line (c/Km)	197927	49852	269571	109440	379011

Source: (Arouje 2015)

The growth of transmission lines in India is shown by the bar chart below in Figure 2.6. Development of transmission lines in India is carried out in accordance with the expansion in generating capacity. Advanced technologies are brought in for the bulk power transmission system. In 1960 220 KV, in 1977 400 KV and in 1990 HVDC Bi-pole transmission was introduced in Indian transmission network system.

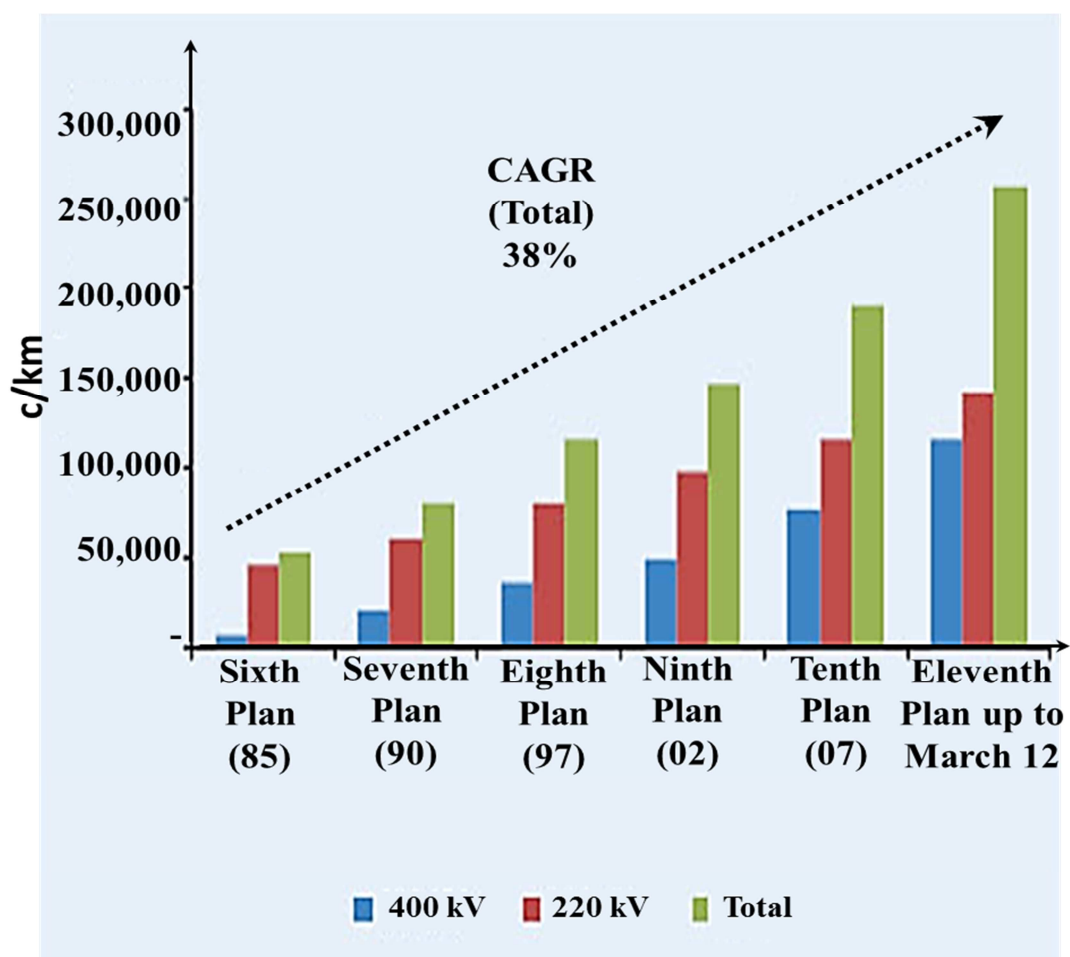


Figure 2.6: The growth of Transmission Lines in India

Source: (CEA 2015)

The transmission pricing evolution in India is shown in the Figure 2.7 where it can be seen that at the end of stage IV Hybrid Methodology was expected and India is still struggling to find the proper Hybrid Methodology for transmission pricing.

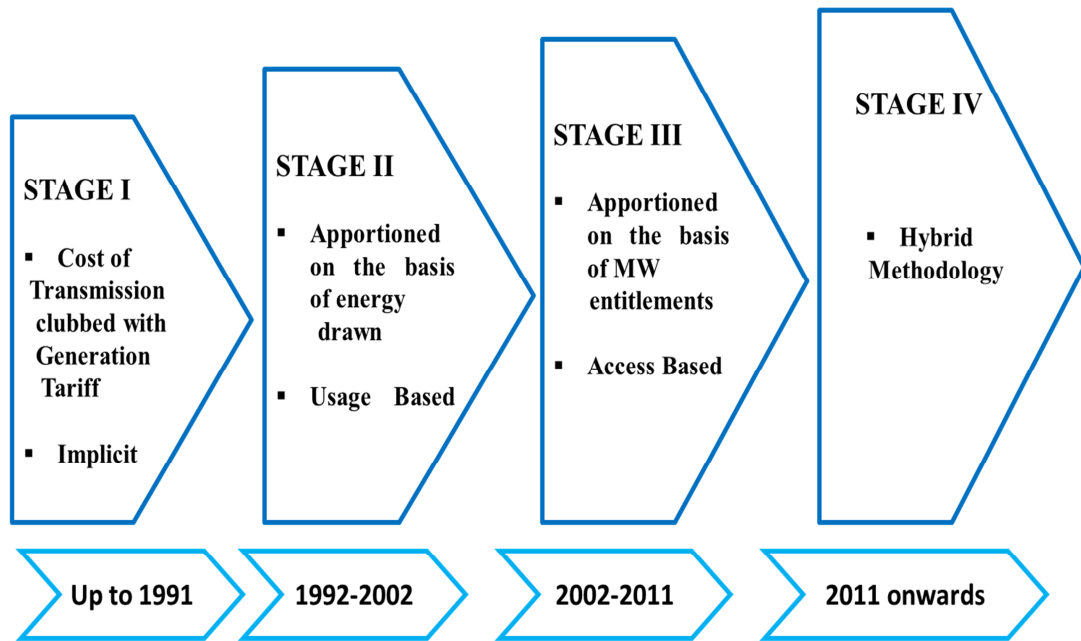


Figure 2.7: Transmission Pricing Evolution in India

Source: (Soonee, Barpanda et al. 2013)

2.2.3 ELECTRIC POWER SYSTEM RELIABILITY IN INDIA

In India, a reliability target planning criterion of 5% (i.e. 8.25 days a year) was adopted in the first National Power Plan (NPP 1983) and in second (1987), which is showing a high level of Loss of Load Probability (LOLP). In the near future, substantial increase in capacity through Independent Power Producers (IPP) is expected. Hence in the fourth NPP it is proposed to improve reliability target planning to 1 % (3.65 days a year) i.e. by the end of the 10th Five Year Plan (FYP).

Up till now, in India the reliability figures being adopted were of LOLP – 1% and Energy Not Supplied (ENS) - 0.15%. This was the case when India was facing a huge power deficit situation. Now, the power shortage is expected to ease out. Therefore from the 12th Plan onwards more Stringent Reliability norms are required to be adopted. USA adopts an LOLP of 0.03% which appears to be reasonable for a developed economy. The LOLP standard adopted by some South Asian countries is

0.27 %. It is therefore proposed that an LOLP of 0.2% and the Energy Not Served (ENS) of 0.05% shall be adopted for planning purposes from the 12th Plan onwards. Reliability Benefits can be included if we have more capacity as it adds to system reliability. The impact of system reliability depends on pricing methods. If the Pricing methods are not well defined the losses in the power transaction will be more and reliability cannot be maintained. In this research study a DMF has been proposed for the reliability evaluation that can be carried out for the Indian sub-continent.

2.3 AVAILABLE TRANSFER CAPABILITY OF TRANSMISSION SYSTEM

ATC gives the overview of the method used for finding the capability of transmission line for transmitting the electrical power which can be further used for finding the appropriate method for calculating each component's contribution in the transmission network.

Available transfer capability (ATC) is the capability of transmission present in the power system network for any more transfer of energy above the contracted usage (Hojabri, Hizam 2014, Khaparde, Abhyankar 2014, NERC 1996).

In order to use interconnected network reliably and intensively in a competitive environment, the knowledge of network capability should be known, which can be gathered using ATC assessment

2.3.1 SIGNIFICANCE OF ATC IN TRANSMISSION SYSTEM RELIABILITY

The importance of ATC in deregulated market persists in order to maintain system reliability, security and restoration. It gives the information about the available

capacity in the transmission network. This information is helpful in making future decisions regarding the next bunch of transaction to be undertaken.

Total Transfer Capability (TTC) is the capacity of the transmission network in which electrical power transfer can be carried out reliably taking care of all the contingency conditions simultaneously.

Transmission Reliability Margin (TRM) is the capacity left in the transmission line to ensure secure transmission under any uncertainty in the system.

Capacity Benefit Margin (CBM) is the reserve transfer capacity by the network to ensure the reliability requirement of the generation.

Mathematically,

$$ATC = TTC - TRM - CBM \quad (2.2)$$

Where, TTC (Total Transfer Capability), TRM (Transmission Reliability Margin)

and CBM (Capacity Benefit Margin)

TTC, ATC and related terms in transmission services are shown in Figure 2.8 below.

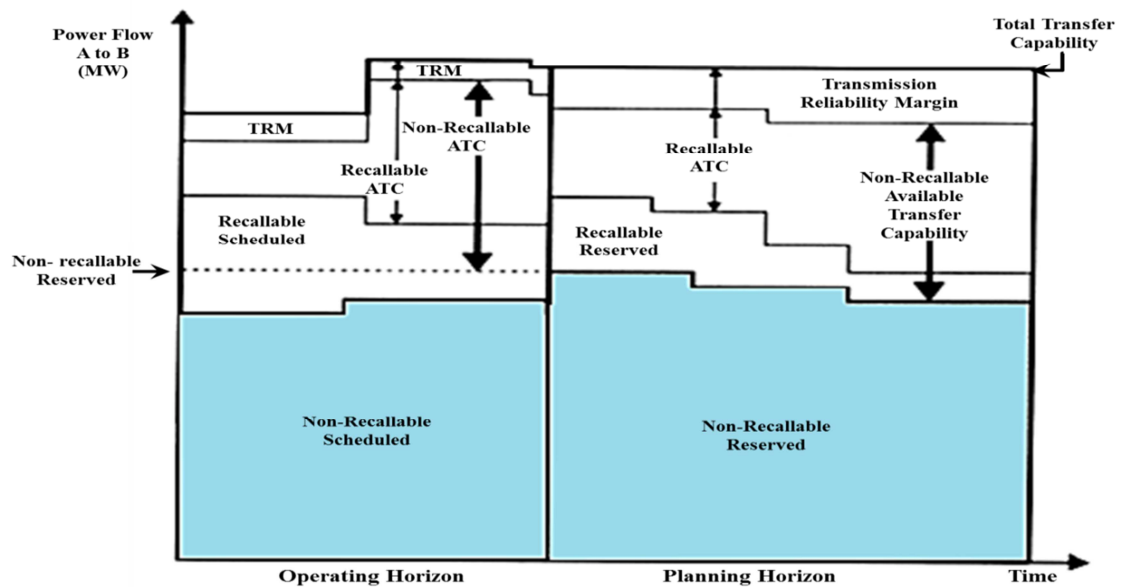


Figure 2.8: TTC, ATC, and related terms in a transmission service reservation system

Source: (Stahlhut, Westendorf et al. 2007)

According to North American Electric Reliability Corporation, (NERC 1996) transfer capability is the function of total generation, demand of customers and the transmission network condition for the particular time period. The transfer capacity is related to the rating of equipment used for transmission i.e. the capacity of network cannot change but capability changes with time and condition of the system.

2.3.2 ATC EVALUATION METHODS

2.3.2.1 Deterministic Methods

2.3.2.1.1 Continuation Power Flow (CPF)

In this method the maximum value of a scalar parameter is found within the linear injection variations at the buses in the power flow. This method considers the influence of voltage and thermal limits as well as voltage breakdown and reactive power factor (Ejebe, Tong et al. 1998).

This method uses the known solutions from the conventional power flow and also uses the tangent predictor method to evaluate the further solution related to the different values of the load parameters (Bhesdadiya, Patel 2014).

2.3.2.1.2 Sequential Power Flow Method

This method solves the power flow equations repeatedly at a progression of points on a predetermined path. It has an advantage of easy convergence and implementation (Umapathy, Venkateshaiah et al. 2010, Umapathy, Venkateshaiah 2007).

2.3.2.1.3 Optimal Power Flow Method

This method is used to find the steady state operation point with minimum cost of generation and it considers thermal and voltage limits in its estimation process (Pandya, Joshi 2008).

2.3.2.1.4 D.C. Load Flow Method

This method is less accurate when the ratio X/R is high. It is fast due to its simple process in calculation and it considers only thermal limits (Khaparde, Abhyankar 2014, Bhesdadiya and Patel 2014).

2.3.2.1.5 Power Transfer Distribution Factor (PTDF) Method

This method uses the fraction of amount of transaction from one point to another in a transmission line (Christie, Wollenberg et al. 2000). This considers both D.C. and AC Power flow solutions (becomes ACPTDF). It is applied to calculate the maximum limit of flow in a pair of transactions between end points. This is one of the sensitivity based power flow methods (Kumar, Gupta et al. 2013, Sookananta 2012, Kumar, Kumar 2011 Kumar, Srivastava 2002).

2.3.2.1.6 Generation Shift Factor (GSF)

This factor gives the amount of change of Power flow in the transmission line due to increased injection at the generator bus and its withdrawal at the swing bus. This is one of the sensitivity factor used to determine ATC (Hojabri, Hizam 2014, NERC 1996).

2.3.2.1.7 Line Outage Distribution Factors (LODF)

ATC can also be calculated by considering the effect of line contingency and using the same concept LODF are used to calculate ATC. During an outage the power flow is distributed among remaining lines and LODF is the measurement of this distribution of fractional power into other lines during outages. For ATC calculation, methods like PTDF, GSF and LODF consider

only thermal limits so the computation accuracy is not very satisfactory (Hojabri, Hizam 2014, Khaparde, Abhyankar 2014, NERC 1996).

2.3.2.2 Probabilistic Methods

Some of the Probabilistic methods used for ATC computation can be classified as

1. Heuristic optimisation methods such as
 - a. Genetic Algorithm (Haupt, Haupt 2004),
 - b. Tabu Search (Glover 1990), Simulated Annealing (Kirkpatrick, Gelatt et al. 1983)
2. Statistic approaches such as
 - a. Monte Carlo Simulation (Xia, Meliopoulos 1996),
 - b. Stochastic Programming (Xiao, Song 2000).

Artificial Neural Network (ANN) have also been used and categorised as the absolute method for ATC calculation (Pandey, Pandey et al. 2010).

2.3.3 TOTAL TRANSFER CAPABILITY OF TRANSMISSION SYSTEM

Total Transfer Capability (Shaaban, Yixin Ni et al. 2000) is the basic measure for estimating ATC. Sequential Quadratic Programming (SQP) method has been used for optimising and comparing the result with CPF method (Ejebe, Tong et al. 1998). The presented method can accurately determine the reactive power flow, voltage limits and the effect of line flow. This approach is able to re-dispatch the reactive power output of generators and distribute the increased load and generation optimally across all the specific busses.

Sookananta (2012) provides the review on transfer capability in power systems. It has been discussed that better understanding of utilization of the ATC calculation method according to its application can be a guide for better planning, provide flexibility in operation under difficult conditions and give power exchange between systems.

It is important to determine the use of capacity for different transactions in the system in order to implement the fair transmission system charges and it also provides beneficial results for managing congestion of the system. Yang, Anderson (1999) suggested the Power Flow Comparison method which was compared with the Proportional sharing method and concluded that the power flow comparison method provides a wide variety of information with regard to the use of transmission capacity and its pricing. The sensitivity advice for the power flow in the critical lines can also be estimated.

2.4 CONGESTION IN TRANSMISSION SYSTEM:

Congestion pricing and its management provides an overview of the presently used method and its importance in Transmission Pricing.

2.4.1 OVERVIEW

In the electrical energy market, the introduction of Deregulation has triggered big competition among the suppliers and consumers resulting in the congestion of transmission lines.

The major issue in terms of security of the power system is congestion management. Congestion of transmission lines is a condition under which economic dispatch can

never be maintained and the generators with high operating costs have to take over in order to maintain stability in the transmission system operation. The main reason for the occurrence of congestion in the network is the violation of some of the constraints of the power system like active and reactive power of the generator, voltage limits and the thermal limits of the transmission lines (Christie, Wollenberg 2000, Shirmohammadi 1998). The effect of congestion is that the generation cost can be increased due to dispatch of more costly generators and that cost will be reflected in the transmission pricing and also in congestion costs that will in turn decrease the overall efficiency of the system (Singh, David 2000) . So it is very important to relieve congestion and charge the network consumers who are responsible for such a condition in the system.

Independent System Operators (ISOs) are formed in the deregulated electrical market environment in order to control and operate a transmission network in an open and transparent manner for every participant of the wholesale electrical market (Singh, David 2000).

Baldick, Bushnell et al. (2011) suggests that the cost of congestion should be properly reflected in the pricing schemes for using the transmission network otherwise in a few locations the demand is more than supply and in some cases there is surplus of supply. The cost of congestion can be evaluated from the condition of those who were unable to use the network due to congestion. The present transmission system demands that sufficient capacity is constructed for transmission where congestion rarely occurs.

2.4.2 CONGESTION MANAGEMENT GENERAL PROCEDURE

Electricity suppliers provide the data for transactions to ISOs before scheduling the generator dispatch. ISOs study the data provided and analyse the effect of all the transactions independently and with the combinations of all transactions evaluate for any violation of transmission constraints. If the analysed details indicate congestion in the transmission network due to some transaction then they do congestion management to remove congestion from the system. ISOs can use two methods for relieving congestion one is cost free and the other is non cost free (Singh, Shangyou Hao et al. 1998).

➤ **Cost free method**

- Congested line outage
- FACTS devices operation
- Transformer Taps operation

➤ **Non cost free method**

- Generator re-dispatch: This is an operative mechanism in which the MW output generated are controlled and readjusted to protect the transmission line from reaching overload condition.
- Load curtailment: This is a process under which the loads are shed to relieve the transmission line overloading.

The analysis is inevitable for the contingency of the power system in order to have a congestion free system as far as possible. In the power system, there can be times when major problems occur so instantly and quickly that even the operator hardly gets the time for the fast action which is required to control the system, and that may result in cascading failures of the system. To tackle such a situation the modern

power system control centres are installed with contingency analysis programs that simulate and suggest a potential problem in a system, before it occurs. These types of contingency analysis programs have been designed for the particular power system and are utilized for evaluation and study of the event responsible for system outage as well as providing the signal for any system overloads or over-voltages during the operational state of the system.

Karaki, Chahine et al. (2002) used the Minimum load curtailment (MLC) problem to manage congestion. For congestion cost estimation and for its implementation on the users, Shih-Chieh Hsieh, Chien-Chih Chu et al. (2002), Bialek (1997) used topological generation distribution factors. Singh, Shangyou Hao et al. (1998) presented a concept of nodal pricing and implemented it in a pool electrical market. To assign congestion pricing for the loads Shirani, Siahkali (2002) proposed a traceable flow method. Rau (2000) presented a nonlinear optimisation method based on optimal re-dispatch for relieving congestion in transmission lines. According to Jun Yu (2002), ERCOT (Electric Reliability Council of Texas) does congestion management in separate zones where loads, generators and transmission grids are separated according to these zones.

Heydaripour, Akbari Foroud (2012) proposed a method for reducing the cost of congestion by pricing ancillary services and re-dispatching real power from generators. The key factor that affects power system security is stability of voltage and it usually occurs in the transmission system which is under heavy power flow transactions. One of the important methods to manage congestion is OPF (Optimal Power Flow) which considers active and reactive power to create a balance between

security and revenue. GA (Genetic Algorithm) and CPF are used to estimate the stability of the voltage margin in the system.

2.4.3 MANAGEMENT OF TRANSMISSION CONGESTION

The process of managing congestion is to eliminate it from transmission network. Usually ISO uses OPF program for conducting a generator re-dispatch in order to control congestion in transmission lines. Sometimes re-dispatch of generators lead to a situation where a costlier generator is put into operation, which increases the cost of production and this increase in cost is known as the congestion cost. This congestion cost has to be distributed among the customers depending upon their contribution to the congestion. Both congestion management and congestion cost allocation have become problematic issues, and to deal with these many researchers have made remarkable contributions. A few methods for managing congestion are given below.

2.4.3.1 Traceable Flow Method

This method calculates the cost of congestion by estimating the cost of energy at each load under constrained and unconstrained conditions. The total congestion cost is determined taking the difference between the energy costs of two cases. Traceable method is used to determine the contribution of load for the line flows. For the constrained network the energy cost is estimated by taking the share of congestion cost of every load from the total cost and adding the energy cost to it under the unconstrained network condition (Malaki, Shirani et al. 2001).

2.4.3.2 Lagrange Multiplier Method

Jung, Hur et al. (2003) suggested this method for determination of Congestion cost using Lagrange multipliers under which the cost of congestion is first assigned to transmission constraints and then to the loads which utilize that constraint considering Lagrange multiplier of transmission constraints.

2.4.3.3 Load Management

Congestion management under this method is conducted by curtailing agreed load effectively. It is assumed in this method that the load curtailment will relieve the network from congestion and the effect of the process is determined by using sensitivity factors which give the change in flow of power due to change in load (Alvarado, Camfield et al. 1997).

2.4.3.4 Nodal Pricing

This method is also known as Locational Marginal Pricing (LMP) as it considers geographical locations. Under this method the revenue collected is more than it costs to industry, and that surplus is given to the contract holder of Transmission Congestion (TCC) or to Firm Transmission Rights (FTR) (Krause 2005).

2.4.3.5 Congestion Cost Indices

This method considers two constraints, active power limits of generators for finding the cause of congestion and limitation of transmission lines to relieve congestion. After that the generator output is controlled to match the same demand. Topological generation distribution factors are used for estimating the contribution of power from each generator for congestion (Shirani, Siahkali 2002).

2.5 DISTRIBUTION FACTORS FOR TRANSMISSION LINE FLOW/TRANSFER SENSITIVITY ANALYSIS

Distribution factors are used for conducting a sensitivity analysis and their importance in the research is that they are used for congestion and transmission costing.

Distribution factors are estimated using A.C. load flow and are used to evaluate the variation in transmission flow due to generators and loads in the transmission network. Some of the distribution factors are GSDF (Generalised Shift Distribution Factors), GGDF (Generalised Generation Distribution Factors) and GLDF (Generalised Load Distribution Factors).

According to Songa, Parkb et al. (2011) in power system security analysis, distribution factors play an important role being a linear approximation of the sensitivity of system variables for variation in the power flow input to the system. In power system, multiple simultaneous faults due to overloading or congestion of lines are the major cause of reducing the reliability of the system.

Rudnick's method (Rudnick, Palma et al. 1995) used distribution factors like GGDF, GSDF and GLDF to find the change in line parameters. Where GSDF takes care of incremental changes of flow in buses, GGDF measures the change in power flow in the buses due to generators and GLDF measures the negative flow of power in buses due to loads.

Bialek's method (Bialek 1996) uses the proportionality principle to evaluate the contribution of each load and generator to the power flow in the transmission line.

Kirschen's method (Kirschen, Allan et al. 1997) uses the same proportionality principle with some variation in application i.e. it is applied to the commons (a set of contiguous bus supplied by same generators).

A method to calculate supplement charge allocation in transmission line-use is proposed by Bialek (1997). This method is implemented by using MW mile method and generation and load distribution factors. Supplementary/Complimentary charge (Perez-Arriaga, Rubio et al. 1995) is the additional charge applied over the marginal cost in order to recover the complete network cost. These charges can sometimes go up to 70% of the total transmission charges.

The topological generation distribution factors are calculated using upstream distribution matrices and the topological load distribution factor is evaluated considering downstream distribution matrices. Acha, Fuerte-Esquivel et al. (1997) have applied the Power Auditing (PA) algorithm and came up with the similar results by using distribution factors.

The customer of the transmission network faces uncertain congestion prices, Minghai Liu, Gross (2004) proposed that distribution factors such as Injection Shift Factors (ISF) and PTDF, which are used to evaluate sensitivity of active power flows, can also be used to set the congestion prices. PTDF's are analysed for the same and the impact of their errors are examined for congestion pricing.

A new and fast method is developed by Singh, Srivastava (1997) to evaluate the set of Distribution Factors by Newton Raphson Jacobian method under base case. These factors can be used to calculate the voltage and reactive power after outage occurs in an electrical transmission system either in branch or in a generator. The indispensable use of these factors is to estimate the voltage and reactive security.

2.5.1. POST LINE OUTAGE DISTRIBUTION FACTORS

Line Outage Voltage Distribution Factor (LOVDF)

Line Outage Voltage Reactive Power Distribution Factor (LOQDF)

Similarly the distribution factors for post generator outage are:

Generation Outage Voltage Distribution Factor (GOVDF)

Generation Outage Reactive Power Distribution Factor (GOQDF)

$$P_l^T = \frac{1}{2} (P_{ij} - P_{ji}) \quad (2.3)$$

$$Q_l^T = \frac{1}{2} (Q_{ij} - Q_{ji}) \quad (2.4)$$

Where, $i = 1 \dots N, j = 1 \dots N_q$

$l = 1 \dots N_l, g = 1 \dots N$

$N_q \neq g$

N- Number of buses

N_q - Number of reactive power sources

N_l - Number of lines

l_1 & l_2 are two factious lines.

P_l^T - Average real power

Q_l^T - Average reactive power

$$\text{LOVDF} \quad a_{li}^P = \frac{\Delta V_i^P}{P_l^T} \quad \text{at line } l_1 \quad (2.5)$$

$$a_{li}^Q = \frac{\Delta V_i^Q}{Q_l^T} \quad \text{at line } l_2 \quad (2.6)$$

$$\text{LOQDF} \quad c_{lj}^P = \frac{\Delta Q_{Gj}^P}{P_l^T} \quad \text{at line } l_1 \quad (2.7)$$

$$c_{lj}^Q = \frac{\Delta Q_{Gj}^Q}{Q_l^T} \quad \text{at line } l_2 \quad (2.8)$$

$$\text{GOVDF} \quad b_{gi}^P = \frac{\Delta V_i^P}{P_{Gg}} \quad \text{at line } l_1 \quad (2.9)$$

$$b_{gi}^Q = \frac{\Delta Q_i^Q}{Q_{Gg}} \quad \text{at line } l_2 \quad (2.10)$$

$$\text{GOQDF} \quad d_{gj}^P = \frac{\Delta Q_{Gj}^P}{P_{Gg}} \quad \text{at line } l_1 \quad (2.11)$$

$$d_{gj}^Q = \frac{\Delta Q_{Gj}^Q}{Q_{Gg}} \quad \text{at line } l_2 \quad (2.12)$$

As per the discussion, it is suggested to extend the use of distribution factors for evaluating the voltage stability predictions under contingency.

Yung-Chung Chang, Yang et al. (1994) have presented a fast economic dispatch method using loss coefficient from LODF and GSDF.

2.5.2 POWER TRANSFER DISTRIBUTION FACTORS (PTDF)

PTDF is defined as the relative change in the power flow on a particular branch from bus 'i' to bus 'j' due to change in power injection and corresponding withdrawal at the system swing or slack bus.

PTDF's are calculated by using Susceptance (B) matrix and distribution factors.

Barbulescu, Kilyeni et al. (2009) have developed a software tool to evaluate PTDF in order to establish the change in specific transaction that affects the system operation.

PTDF are used to calculate the power flow change due to a change in load at certain buses.

2.5.3 SIGNIFICANCE OF PTDF IN TRANSMISSION COSTING

According to Khaparde, Abhyankar (2014), 'PSERC' (2001), PTDF is used to determine the sensitivity of power flow variations with respect to the power flow in any transaction. It is a transmission line dependent factor which evaluates the percentage of the increased power flow in the transmission line. It also provides information about the location specific power injections and its effect on transmission lines and transformers. This information can be used for economic dispatch and to deal with transmission congestion. They are also used to measure the effect of economic exchange on the power flows in the overloaded transmission line. PTDF can calculate the change in power flow in transmission lines due to change in power from one node to another.

Alvarado (1999) considers PTDF as a vital component in a deregulated power system structure for determining the congestion management and pricing planning.

PSADD (Power System Application Data Dictionary) has been utilised to determine the power flow and PTDF quickly and efficiently. The data dictionary is implemented in MATLAB. If PTDF at any one point is known then the PTDF for any bilateral exchange when the slack generator is not considered can be determined. To determine PTDF the Jacobian matrix is made which gives the relation of flow of power at both ends of the line with the variation of magnitude and angles of voltage.

According to Baldick (2003) the value of PTDF changes with the variation in the point of operation, the structural changes in the network and also with the power system control elements reaction for overload. If there is a variation of PTDF in a transmission network then it is arduous to estimate the required capacity level for

bidding in flow gate as per flow gate rights schemes for transmission rights (Chao, Peck 1996).

The limiting factor in the thermally controlled line is not the flow of power but the resistive losses in the transmission line, and as we know resistance is inversely proportional to the square of current in the line, PIDF (Power to Current magnitude Distribution Factors) are used to investigate the variations in the power flow on the current magnitude of line. PTDF's remain moreover constant in the line during different loading conditions. When the voltage between two ends of the line changes the value of PTDF also changes. This is due to the fact that the change in voltage difference changes the flow of reactive power that rapidly changes the value of PTDF. The PTDF determination for simultaneous multi-transactions in the system using DC load flow is developed by Kumar, Gupta et al. (2013)

2.5.4 A.C. POWER TRANSFER DISTRIBUTION FACTORS (ACPTDF)

ACPTDF based approach along with N-R method can be used to determine ATC for different transaction in the transmission network. The capability simulations for this approach will be performed offline. ACPTDF are the indicators of network performance and ATC under operational conditions ('Saloni', 'Dhakla 2013).

Kumar, Srivastava (2002) describes the methodology of loading allocations on the transmission line using ACPTDF that can be defined using the sensitivity properties of the N-R load flow Jacobian as a base case. DCPTDF's has low accuracy in determining the power flow in the line as it makes some assumptions in the power flow model. ACPTDF computation is quick and can be used during any variations in the operating conditions of the system.

Using the ACPTDF approach, Kumar, Kumar (2011) has developed a method for multi transaction cases considering power transfer sensitivity and Jacobians. The simultaneous and multi-transactions cannot be avoided for ATC determination in order to achieve an accurate signal for justified commercial transaction. The ACPTDF approach can be implemented online for ATC calculation.

2.5.5 LINE OUTAGE DISTRIBUTION FACTOR (LODF)

LODF are the linear estimate of power flow change in adjacent lines during outage and are used to evaluate the overload in the lines due to the fault.

PTDF and LODF are evaluated and used to estimate the generator shifts to ensure that the power in the transmission line due to outage remains within the security limits.

To estimate the contingency in the power system LODF are used because of their accuracy and fast evaluation. LODF is expressed and calculated in terms of PTDF just before overloading (Jiachun Guo, Yong Fu et al. 2009).

As the blackouts are usually caused due to cascaded outages, LODF for multiple line outage evaluation is necessary for power system security. Generalized LODF (Güler, Gross et al. 2007) are being derived and applied for the evaluation of power system security.

GLODF can be very useful in determination of island formation and causal factor identification during multiple line outage conditions.

2.6 TRANSMISSION PRICING REVIEW

The Transmission pricing review enlightens us with the methods that are being used in the different countries and the process of their implementation.

The transmission pricing is the process which helps the transmission service provider to optimally recover the cost of supplying the electricity to the customers (Kharbas, Fozdar et al. 2011).

According to Spreeuwenberg (2011) report, the transmission pricing and connections should be compatible to deal with failure in the system and should fit to the new regulatory rules and any market expansion and arrangements. For the U.K. it was emphasized to carry on the Locational TNUoS (Transmission Network Use of System Charges) and Baldick and Newbery supported Locational Marginal Pricing (LMP) being cost effective for transmission pricing and Congestion management. Murali, Kumari et al. (2014, 2011) presented a review of the different types of charges involved in transmission pricing and discussed the different methods used for estimating the existing and future cost of transmission. From the comparison, it has been concluded that the flow based method is a better method for estimating prices and Kirschen method is more accurate and reliable of all for power tracing and transmission pricing methods. The optimal method for recovering the actual transmission charges should contain both incremental and embedded pricing techniques. Al--Rajhi, Bialek (2002) have carried out comparisons of marginal and tracing methods for transmission pricing. They explained that the investments which are non-divisional cannot be recovered from a marginal pricing method and moreover, it also fails to recover adequate revenues required to keep the firm

operational for the long run. Pricing based on a tracing method displays stability and transparency and considers the spatial factors reasonably.

Bell, Green et al. (2011) in their discussion point out that neither of the refined long run based methods, locational marginal pricing with Financial Transmission Rights (FTR's) and Postage Stamp methods are ideal and nor are they consistent with economic efficiency. They are moreover sensitive towards any small change in the transmission system. The Great Britain (GB) electrical system operators recovered the cost for balancing the revenues using 'Balancing Services Use of System' charging, which is one form of Postage Stamp Method. Transmission charging methods containing locational elements do not recover the overall cost of the transmission owners, so it has been suggested to include some additional residual cost into Postage Stamp Method to recover total cost of transmission. But the discussions are in process for the basis of that residual element, whether it is power or energy based.

2.6.1 IMPORTANCE OF TRANSMISSION PRICING

As the cost of transmission is a substantial part in transmission pricing, many methods along with MW-Mile methods are developed to recover the cost based on usage of transmission capacity. Charging for ancillary services in the transmission system is another big issue and it is divided between the customers according to the demand plans. To measure the magnitude of usage for the transmission capacity, there is still no general rule. It varies and depends upon the market structure. Pan, Teklu et al. (2000) has presented a work on usage based cost allocation in

transmission system under open access. Recent methods for recovery of fixed transmission charges and other possible techniques for pricing are also discussed.

2.6.2 METHODS REPORTED IN THE LITERATURE FOR TRANSMISSION PRICING

Pricing of transmission services using both MW-Mile method and Postage Stamp method in order to derive a fair and transparent transmission price allocation is performed by Kharbas, Fozdar et al. (2011). All the three forms of MW-Mile methods (Meah, Mohamed et al. 2003) i.e. Absolute, Dominant and Reverse are separately used along with Postage Stamp method for result verification. It has been found that the Reverse MW-Mile methods along with Postage Stamp method are quite sufficient to recover the total transmission cost at optimal and transparent levels. They also assists in lowering the overloading of transmission line and hence Congestion in the system. This process of price allocation is simple and practicable. The Postage Stamp method is used to recover and distribute the charges of the unused capacity among the customers proportionally. The unused capacity/residue is calculated as,

$$R_k = \frac{\Delta TC * P_{LK}}{P_{LT}}, \quad (2.13)$$

where, R_k : Unused capacity to each customer k ,

P_{LK} : Load of customer k ,

ΔTC : Difference or total unremunerated charges,

P_{LT} : Total load.

Transmission cost allocation, considered with and without transmission losses is undertaken by Varma, Sankar (2011). Postage Stamp method and Flow based

methods are used to calculate transmission pricing and thereafter the results obtained from both the methods are compared. It has been concluded that the Flow based method is fairly and efficiently charging the transmission cost from the users as compared to Postage Stamp method which allocates unconvincing prices to some customers and generators.

2.6.3 THE TRANSMISSION PRICING METHODS EVALUATED IN DETAIL

This section describes the transmission pricing methods evaluated and used to calculate the transmission cost for comparing the proposed application of PTDF method for transmission costing. The Flow chart for the methods is given in the methodology section of chapter 5.

LMP in itself is not sufficient enough for covering revenue for the Transmission sector. It has to be covered up by some additional charges to make up the overall cost of transmission. Present mechanism for pricing favours distant locations and also renewables, rather than minimising the cost of transmission for the customers' welfare and making an affordable utilization of electrical energy. There is a need for generation from intermittent and dispersed sources to cover future demand and also to construct the transmission network for supporting the generated power and transfer it with least congestion in the network. LMP method is the transparent and efficient method which covers congestion, transmission losses and the electricity charges together (Newbery 2011).

The Marginal Transmission Pricing method along with the Distribution Factor method are applied for collection of revenues from transmission of electrical power

and also for allocating supplement charges for the different users involved in the process. An open access scheme has been developed for the Chilean power system network. The purpose of this work is to solve the issues of the supplement charge distribution among the generators which is affecting the development of transmission system and the investment plans for the future (Rudnick, Palma et al. 1995).

A thorough analysis of marginal pricing methods for estimating the transmission network cost has been carried out by Perezarriaga, Rubio et al. (1995). It has analysed that marginal pricing method is unable to calculate the complete network cost incurred in the transmission network. It has also analysed the effects of marginal pricing on the regulatory schemes of the electric power industry. The analysis is based on active power and can be applied to reactive power. The long-term marginal pricing can recover the total cost of transmission considering reliability constraints whereas, short term marginal cost is unable to recover the actual cost of transmission itself and that is why a supplementary charge is necessary for recovering the actual cost of electrical power transmission.

According to Christie, Christie et al. (2000) transmission pricing management can be achieved using four methods: transaction based, Optimum Power Flow (OPF) based, price area based and distribution based. But all these methods require more research in order to achieve a balance between better system reliability and market economics. The nodal pricing method based on SRMC for generating the revenue for transmission of electrical power has been suggested by Saini, Saxena (2009) and they found that it can be best utilized to maximise the social welfare. New expressions are developed for real and reactive transmission pricing using GA and fuzzy based OPF.

The fundamental concepts for pricing transmission services and how it can be used for efficient economic development of transmission industry are described by Shirmohammadi, Filho et al. (1996). One of the considerations for transmission pricing is to determine the possibility and cost of electrical energy supply and the other factors are the political and market considerations which are equally important in estimating the price for the transmission services. It also explains that the transmission pricing paradigm is the process of converting transmission cost into transmission charges.

Orfanos, Tziassiou et al. (2011) has analysed transmission pricing methods that consists of embedded and marginal price evaluation techniques and a few tracing based methodologies for pool based electrical markets. The conclusion made is that the MW mile method can recover all the transmission cost but is unfair for consumers who cause counter flow in the network whereas; Bialek's tracing method and minimum distance method charges nothing for the counter flows. The Distribution factor method is very sensitive to the operating conditions of the system and charges all the users of the network. Reverse MW-Mile method sometimes charges very high for some consumers. A supplementary charge can reach up to 32.5% of the fixed transmission charges for the used transmission capacity methods. It cannot be easy to judge which pricing method is best for transmission pricing but it can be chosen depending upon the network topology and the location of load and generators.

According to Edirisighe, Herath et al. (2002) nodal transmission pricing is the fairest cost reflective method for substations. It calculates and prices the losses incurred due

to transmission and also the uncertainties involved in it. Using this method fairness and economic efficiency can be maintained.

For the improvement in the accuracy of transmission pricing evaluation techniques the knowledge of some points are necessary such as Load, technologies available for transmission with their constraints, developmental and planning policies and environmental constraints (Brinckerhoff 2012).

A new pricing method for transmission services of electrical power which can reasonably and fairly recover the fixed and variable cost along with the cost of future development of transmission network is presented by Arabali, Hosseini et al. (2012). The combination of modified MW-Mile method and the distribution factors are used for the calculation of transmission pricing which include cost of used and unused transmission capacity in the transmission cost.

Considering the Indian power system network Raja, Elakkia et al. (2011) has proposed a new pricing method for transmission services. To calculate the Transmission cost with full recovery a marginal participation method has been proposed which considers the network branch usage in terms of power flow increase in that branch if the load/generation increases marginally. It is considered to be appropriate for transmission pricing as it considers each network branch separately and calculates its relative use.

Among the methods discussed above, Bialek's method and MW- Mile methods are chosen for further investigation and development of algorithms and the suite of programmes used for comparison within the DMF with the proposed application of PTDF method for ROTC. The broad features of these pricing methods makes them suitable for use with other short term pricing methods, which catagorises their use as

Hybrid pricing methods (see figure 5.2). These methods as used in the research work are explained in detail in the methodology sections of the respective chapters in part 3.

2.6.4 SIGNIFICANCE OF POWER FLOW TRACING IN TRANSMISSION PRICING STUDIES

Power flow tracing is used for tracing generator cost and the cost of use of line. For calculating the generator contribution for power flows branch node incidence matrix is used (Acha, Ambriz-Perez et al. 1997).

Due to unbundling of transmission services the level has reached where it is necessary to know the amount of active and reactive power flow from each generator to every load. Considering the fact Bialek (1996) has proposed a method for power flow tracing which can be applied to active and reactive power flows, a loss-apportioning algorithm has been proposed which evaluates the transmission loss in individual loads and generator by breaking it down in to the allocated components. With the use of the tracing method it will be possible to actually charge the generators/suppliers for the losses in the transmission system and hence will encourage efficiency. The proposed method is of a topological nature and can work on state estimation or power flow programs.

A methodology for pricing transmission services in a meshed network has been developed by Kattuman, Green et al. (2013) that can also be applied for inter-system trades. It can be achieved by tracing the path of power flows from source to sink. The proportional sharing principle is explained using co-operative game theory (Bialek 1996) . Power Flow Tracing is used for charging cross border transmission.

A methodology to trace each generator output and cost of production in the whole electrical network by determining the contribution of each generator for total power loss and its cost in the system is identified by Acha, Ambriz-Perez et al. (1997). In this paper the clear information of which generator is supplying which load and at what cost is evaluated.

A technique of proportionality assumption for calculating the generator contribution to the loads and the proportion of transmission line used by each generator is described by Kirschen, Allan et al. (1997). This method is not restrained to the changes due to increased power generation and can be applied to both active and reactive power independently. Palma, Rudnick (1997) discuss the contribution of the proposed method on the transmission pricing and suggest that the method in itself is not sufficient enough to estimate transmission pricing as it does not take the consideration of the cost of network security.

A Transmission system usage determination process is suggested by Strbac, Kirschen et al. (1998) for load and generators and their contribution for the maximum flow in each branch, from which the fair share of each user for using existing transmission facility, can be calculated with ease. Bialck (1998) discussed that the method can also be used for transmission pricing using physical power flow but it does not explain whether the price is divided as per incremental or on average basis.

A method for determining the amount of active and reactive power output of each generator shared among every load has been proposed by Kirschen, Strbac (1999). It is carried out by converting the injected power into real and imaginary currents and then these currents are tracked to calculate the amount of current contribution from generator to load and then current is converted back to contributed power.

A reactive power pricing method which uses power tracing for pricing taking into account the transmission of reactive power and the cost of production is developed by Dai et al. (2003). The two ways of charging ancillary services are by load power factor penalty and by the cost of ancillary support. Embedded pricing based on uniform allocation of production cost is used for reactive power pricing.

The Transaction Based Power Flow (TBPF) method (Huang and Zhang 2001) is developed to determine the utilization of transmission line among the transactions and also to analyse the role of reactive power in the real power flow as well as for transmission loss. The TBPF method is very accurate for managing congestion than the GAPP (Kavicky and Shahidehpour 1996) method. GAPP (General Agreement on Parallel Paths) is a modelling approach which is based on NERC (NERC 1996) operating studies and its main aim is to observe and regulate the effect of parallel transmission lines.

The Equivalent Bilateral Exchange (EBE) method is proposed by Galiana, Conejo and Gil (2003) for pricing transmission services from users and the method is based on the concept that every generator will take an equal share of each load and vice versa. The inspiring aspects of this approach are counter flow recognition, slack bus independence, uniformity and positivity of transmission charges. This method is compared with PSP (Proportional Sharing Principle) (Kirschen, Allan and Strbac 1997) which does not allow the reverse power flows. There is a difference in charging principle between two methods i.e. EBE charges for all lines but at a smaller rate and PSP charges for a few lines with higher usage rate.

Modified Tracing Method (Bialek, Ziemianek et al. 2004) can be used for pricing transmission services during cross border trades. In this method the loss is allocated

directly and a unified tracing of power flow is undertaken for allocating transmission pricing for cross border trades. The only data required in this method is power flow in the Tie Line and the charges are set at the border points of each state/country.

Danitz, Rudnick et al. (2002) has compared the three methodologies in accordance with pricing of transmission services as per usage and concluded that all three methods are reasonable for transmission charge allocation.

2.7. RELIABILITY EVALUATION OF ELECTRIC POWER SYSTEM

Reliability is very important in the present scenario for operating electrical transmission system more efficiently and economically.

2.7.1 OVERVIEW

The function of an electric power system is to provide electricity to its customers efficiently and with a reasonable assurance of continuity and quality (Billinton, Allan and Salvaderi 1991).

Reliability is the probability of a device or system performing its function adequately, for the intended period of time, under the intended operating conditions (Endrenyi 1978.).

Reliability refers to the probability that a component or a system comprising components is able to perform its intended function satisfactorily during the given period of time under normal operating conditions. Thus the reliability assessment of a power system is mainly concerned with its capability, which is related to the existence and availability of sufficient facilities to satisfy customer load.

Power system reliability, in a broad sense, can be defined as the ability of the system to provide an adequate supply of electric power with quality satisfaction.

Power systems have three main components: Generation, Transmission and Distribution systems. The generation system generates electricity and transmission system delivers the generated electricity to distribution systems for supplying load. The generation system together with transmission system is usually called the composite system or the bulk power system.

As the total power system is so enormous in size, the reliability evaluation has been performed separately for all the three levels HL-I, HL-II, HL-III as shown in Figure: 2.9 (Billinton and Jonnavithula 1996).

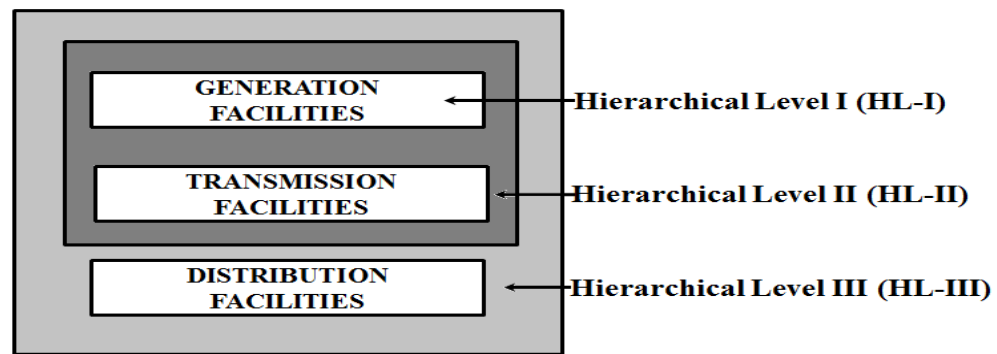


Figure 2.9: Reliability Assessment Hierarchical Levels

For the generation and distribution system the reliability evaluation techniques are well developed, so the research is concentrated more on the bulk power system reliability analysis (Ibe and May 2013).

According to Endrenyi, et al. p.63 (1982) reliability evaluation in transmission systems is not so well developed because of conceptual problems like purpose and uses, selecting inappropriate events of failure and moreover indices involved in evaluation of reliability also depend on selection of risk levels. Other problems might be in modelling a system, the computational method used and lack of sufficient data

available. For bulk power system planning the first concern is to avoid uncontrolled interruption, then cascading outages.

Reliability studies are conducted for two purposes- first, long-term evaluation is performed to assist in system planning and secondly, short-term evaluation assists in day to day operating decisions.

2.7.2 CALCULATION OF RELIABILITY

Reliability can be measured through the mathematical concept of probability by identifying the probability of successful performance with the degree of reliability.

The reliability of a composite power system is comprised of both adequacy and security assessments (Endrenyi et al. 1982 p.63.). Security and reliability are two important challenges in the restructured Power networks (Kirschen and Goran 2005).

Composite Power system reliability assessment is necessary to determine the indices of reliability. This gives an idea of operation and planning of the generation system. It also provides outage and line capacity analysis and planning of the transmission system (Endrenyi, J. 1978).

Billinton, Oteng-Adjei (1991) suggested that in order to determine a reasonable level of system reliability the marginal cost of providing the reliability can be compared to the marginal worth of that reliability.

2.7.3 ADEQUACY ASSESSMENT OF SYSTEM

Adequacy assessment relates to the ability of the system to supply the energy requirements of customers in a satisfactory manner. Since adequacy assessment deals with static conditions, it does not include the evaluation of the system in response to

transient disturbances i.e. it gives the level of assurance with respect to system's capability to feed all the loads attached to it.

Adequacy, according to Power Systems Engineering Committee (1978) is the capability of a system to fulfil the demands under the ratings of major components, within the environment of scheduled and forced outage of generation and transmission components and facilities.

2.7.4 SECURITY OF SYSTEM

Security assessment deals with the ability of the electric systems to survive sudden disturbances such as electric short circuits or unanticipated loss of system elements. This includes the response of the system caused by the loss of generations and transmission lines. Security gives the assurance that the system can avoid and overcome widespread power interruptions. Voltage collapse, overload cascading and instability come under security analysis (Endrenyi et al. 1982).

In power systems, reliability standards are given as basic technical requirements to be considered and fulfilled during operation and planning. Those requirements are generally known as 'Ancillary Services', necessary for the system integrity and it ensures the production and distribution of power throughout the electric grid. Ancillary services include coordinated system operation, frequency control, energy balance, voltage support and generation reserves. The ancillary services support basic energy supply and delivery functions that are essential for bulk power system reliability (Hirst and Kirby 1998).

In the past, reliability analysis has focused primarily on adequacy assessment. Power system security assessment, however, becomes an important issue for planning and

operating power systems under a deregulated environment. In a highly competitive environment, security assessment should be conducted in a more realistic manner so that the investment of resources can be accomplished in a cost-effective manner. Generally, there are two fundamental approaches in a security study. The first is the deterministic criterion and the second is the probabilistic criterion.

The indices used in reliability evaluation are probabilistic and, consequently, they do not provide exact predictions

2.7.5 RELIABILITY EVALUATION MODELLING METHODS FOR BULK POWER SYSTEM

Li, Choudhury (2007) discussed the aim of transmission planning which is conducted primarily to make the system economical as far as possible and to maintain reasonable levels of reliability of the system. Across many power industry N-1 deterministic criteria (International Power System Deterministic Planning Standard) has been used but it suffers from two main demerits. Firstly the probability of failure occurrence of the component is not considered and secondly, the multiple failure of a component is not considered in the evaluation process. Above all the uncertainty in load forecasting and the location of future generation is very hard to evaluate. Probabilistic transmission is used to improve the transmission planning along with the N-1 criteria as it considers multiple component failure using quantified reliability evaluation. Probabilistic transmission planning provides the total planning approach that contains environmental, technical, social and economical evaluation along with reliability evaluation (Ibe and May 2013).

2.7.5.1 Deterministic Criteria

To maintain system reliability, most utilities use deterministic criterion with a safety margin to cover all uncertainties such as an overload, voltage collapse and transmission line faults. The deterministic criterion indicates whether a system is secure during certain outages.

In this method the contingency list is prepared considering the outage of some important power system components. Keeping this in mind the planner tries to keep a constant look at those factors to prevent contingencies and system failure. As the power system has become more complex with unpredictable form of power flow, the informal list of contingencies becomes less reliable to prevent contingencies (Billinton 1969).

The calculation of this criterion is simple and requires little data. However, it cannot directly indicate system reliability and does not reflect the likelihood of component failures.

The procedure for deterministic criterion is as follows.

- Select the initial load condition, generation dispatch, and network topology that is a base-case model for operational planning of the system.
- Select contingency set.
 - Type of fault
 - Location of fault
 - Faulted element and the switching time
- Evaluate system response and identify violation of the performance criteria.
- Identify the most serious contingency and the limit for each critical parameter.

2.7.5.2 Probabilistic Criteria

The electric power utility industry is undergoing a tremendous change in the deregulated environment. Since the introduction of deregulation, the tough competition level leads system to operate closer to their limits due to which the deterministic criterion may not result in efficient utilization of resources. Also the stochastic nature of the power system behaviour demands considerable application of probabilistic methods for evaluating the power system reliability. Under these circumstances, the uncertainties which affect the reliable operation of power system are analysed.

In the Ibe and May (2013) paper the Markov process has been used to determine the probability, frequency and duration indices for system failure.

Probabilistic criterion can recognize the probabilistic nature of system components. These methods fall into two broad categories: analytical methods and Monte-Carlo simulation methods.

Analytical methods represent the system by mathematical models and use direct analytical solutions to evaluate a priori reliability indices from the model. Monte Carlo simulation methods estimate posterior reliability indices by simulating the actual random behaviour of the system.

This research uses Monte Carlo simulation method to evaluate reliability indices of the power system.

2.7.5.3 Fuzzy Probabilistic Criteria

For modelling the power system reliability fuzzy concepts are also been utilised to analyse the uncertainties in the reliable operation of power system and these are

integrated with the probabilistic approach to modify the results and analyse the system behaviour with more uncertainty introduced (Billinton, Allen et al. 1991).

2.7.6 RELIABILITY ASSESSMENT METHODS

For reliability assessment two methods are applied, they are contingency enumeration or analytical method and Monte Carlo simulation method (Salvaderi, Allan and Billinton 1991, p. 227-228).

2.7.6.1 Analytical Reliability Assessment Methods

Analytical methods are based explicitly or implicitly on contingency enumeration and compute reliability indices by using mathematical solutions. To analyse the causes of contingencies predetermined criteria are developed. Once the contingencies are selected, the evaluation of security breach under given conditions is carried out by using a suitable flow and stability calculation technique until all the selected contingencies have been evaluated. In this method, the contingency states are selected in ascending order and this process stops when the component outage level is less than the specified value. All the states are accessed only once during the whole process and the reliability evaluation is carried out mathematically using statistical data of every state (Ibe and May 2013).

In contingency enumeration analysis simplified mathematical models are evaluated to find reliability indices using analytical solutions. It was first developed in North America (Salvaderi, Allan and Billinton 1991, p. 227-228).

According to Blumsack, Lave and Ilić (2007) topological conditions can be described using analytical expressions, to estimate the conditions required for providing reliability and congestion as an independent entity.

The advantage of analytical methods is that accurate results can be obtained if all the states in the state space can be enumerated and evaluated. The application of probabilistic criterion using the analytical methods in security assessment has already received some attention. Analytical methods based on conditional probability, however, require intensive computation effort when applied to a system with many components.

Security constrained adequacy evaluation (SCAE) using analytical techniques has been proposed by Ibe and May (2013) to increase the efficiency in reliability evaluation process and the system is modelled analytically to calculate the system contingencies.

Hirve and Deshmukh (2013, p.151-156) in their paper evaluated reliability indices of conventional power generating system using an analytical method which is simple and straight forward in estimating reliability.

Dalabeeh and Al-Hajbi (2014, p.45-55) used an analytical algorithm in their paper to determine the operational solution for maximising profits

2.7.6.2 Monte Carlo Simulation Method for Reliability Assessment

The technique which has a great impact in innumerable fields of computational science is a technique called 'Monte Carlo Simulation'. This technique derives its name from the casinos in Monte Carlo. A Monte Carlo Simulation uses random numbers to model some sort of the process. This technique works particularly well

with the process where the underlying probabilities are known but the results are more difficult to determine.

In Monte Carlo simulation, the system states are randomly sampled and then the reliability indices for the random states are calculated and analysed under the prerequisite tolerance level. In this method the probable risky states are sampled and simulated many times. The expected value is judged by taking the average of the value obtained from each simulation.

Some of the advantages of this method are that, it can be performed on any system model for power flow and also the problem of non-consistency can be overcome and the sampling for all the contingencies which occurs in the system can be performed (Oliveira, Pereira et al. 1989, Noferi, Paris and Salvaderi 1975 p. 249-259).

According to Endrenyi et al. (1982 p.64.) for transmission system reliability evaluation probabilistic approach (Monte Carlo Simulation) can be used along with analytical methods. Under Monte Carlo simulation, random processes are considered for the actual behaviour of the system and the results are obtained by taking out the average of all the outcomes of probabilistic data sampling. This method was first developed and used in Italy (Salvaderi, Allan and Billinton 1991, p. 227-228).

There are two basic approaches for Monte-Carlo simulation, namely; sequential simulation and non-sequential simulation. In non-sequential simulation which is also referred as random sampling, a system state can be determined by random sampling based on the probability distributions of the component states regardless of the sequence of occurrences. It is difficult to compute the index of frequency using this approach. The sequential simulation is based on component state duration. It

proceeds by generating a sequence of events using random numbers and probability distributions of random variables.

The sequential approach can be used in studies related to power generation and the random approach is applied to transmission system for reliability evaluation (Endrenyi et al. 1982 p.64.).

Further, there are two methods in sequential Monte-Carlo simulation, i.e; the fixed interval method and the next event method. In the fixed interval method system states are updated with a fixed interval whereas, in a next event method system states are updated at the occurrence of an event. Monte-Carlo simulation is suitable for analysing complicated systems such as a power system, but it also requires large amount of computation time to achieve satisfactory statistical convergence and the characterization of repeated sampling states for security assessment.

Monte Carlo Simulation: (Endrenyi et al. 1982 p.64.) Some beneficial features are-

1. It can be used for complex systems.
2. Easy modifications and random quantities can be used as input.
3. Detailed description.

Although, it takes large computing time, the overall cost of running this program is far less as compared to the gains acquired in having accurate solutions for system planning problems.

According to Oliveira, Pereira and Cunha (1989 p.1309-1315) the Monte Carlo method is used when complex features have to be introduced. They developed a new technique to reduce the amount of sampling in Monte Carlo evaluation. This method uses analytical data as regression variables to reduce the variance of LOLP and EENS. Sample size is also considerably reduced up to second order using this

method. An enumeration based technique is efficient for small system having few outages.

2.7.7 REVIEW OF RELIABILITY INDICES

Many reliability indices and software programs have been operated successfully in reliability analysis of large scale power transmission system.

Bian, Rastgoufard and Davey (1992. p. 213-216) finds the reliability indices of a power system following the three dimensions of reliability i.e. frequency, duration and magnitude. A computer program is also developed to determine the reliability indices which are also tested on the real system.

Many software packages has been developed and utilized for the determination of composite system reliability indices for large scale power system (Billinton, R and Khan, E 1989).

For composite power system reliability studies or evaluation certain indices are generally measured such as Bulk Power Energy Curtailment, Bulk Power Supply Average, Bulk Power Interruption Index, Probability of Failure (LOLE), Frequency of Failure, Expected Load Curtailed, Energy Not Supplied (LOEE), Expected Duration of Load, Average Number of Curtailment/Load Point/Year (Billinton and Allen 1984).

Load point indices for radial distribution system like failure rate (λ), outage time(r), annual unavailability (U) and energy not supplied has been calculated for separate load points. System indices like SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index), CAIDI (Customer Average Interruption Duration Index), and ASAI (Average Service Availability

Index) are also evaluated for group of load points and for the whole distribution system (Billinton, R and Khan, E 1989).

Ibe and May (2013) in their paper used the Markov process to determine the probability, frequency and duration indices for system failure.

Endrenyi et al (1982 p.64.) discusses three things in their paper. First: the selection, evaluation and determination of reliability indices for contingencies. Second: the methods and models of reliability evaluation, basically Monte Carlo method. Third: the data requirement for the reliability studies.

Billinton and Bhavaraju (1970 p.28-34), Billinton (1969 p.276-281), discussed a conditional probability approach for determining reliability indices. The Markov process is used to evaluate the effect of storm on system probability under system failure.

There are several power system reliability indices which are based on the continuity of services to the consumers, the quality of power supply, the effects of unreliability on price and losses etc.

According to Noferi, Paris and Salvaderi (1975 p. 249-259) the quantitative reliability evaluation is performed by risk indices, which are generally of two types:

1. Static index: this consists of generation and transmission capability and their components availability.
2. Dynamic index: this constitutes the dynamic performance of the system under transients.

Vijayamohanan (2008 p.6953) reports that power system reliability is measured in terms of two indices, viz. instantaneous availability and steady state availability (long run availability).

Billinton and Wangdee (2006 p.345-352) used Monte Carlo probability method to determine reliability indices.

Abdul Jaleel and Fathima (2013 p 119-124) used ETAP (Electrical Transient Analyser Program) to model and obtain the reliability indices to calculate the system reliability. They emphasise on the importance of load flow in determining the reliability of a power system and justify it by determining the reliability indices. SAIFI, SAIDI, CAIDI, ASAI, ASUI, AENS, EENS are some of the indices calculated using ETAP software.

Singh and Mitra (1997 p.471-479) discuss a strategy for registering the reliability indices of a composite generation and transmission system by performing Monte Carlo simulation specifically on those areas of the state space where loss of load states are more prone to happen.

Billinton and Wangdee (2006 p.345-352) developed a software program to calculate the probability distribution reliability index at individual delivery points. Delivery point reliability index is eventually affected by the load shedding schedule and operating procedures. The composite power system behavior can be understood by the reliability index probability distribution. Sequential Monte Carlo simulation has been used to determine the mean values and distribution reliability indices. According to Eassa, Elnahass and Attia (2007 pp.226) the purpose of reliability is to evaluate the indices which describe the performance of system w.r.t. system reliability.

The typical indices used in power system reliability evaluation are the following

- Loss of Load Probability (LOLP) – It is the probability where some portion of load demands may not be satisfied by the available generating capacity under the

specified operating conditions and policies. LOLP is currently the most widely used reliability index.

- Loss of Load Expectation (LOLE) – It is the expected period of time during a given period, in which the daily peak load is expected to exceed the available generating capacity. The LOLE per hour can be obtained by multiplying the LOLP by 8760 hours. LOLP and LOLE are often used interchangeably.
- Loss of Load Frequency (LOLF) – It is the expected number of occurrences during a given period of time when the system fail to meet its load demand.
- Expected Unserved Energy (EUE) – It is the expected amount of energy during a given period of time that the system may be unable to supply to the consumers due to the loss of generation or load uncertainty. Typical unit is MWh/year.

Typical reliability indices used in power systems evaluation are the following:

- Load Interruption Indices: Average load interrupted per period of time.
- Loss of Load Probability: Probability of load exceeding available generation.
- Frequency and Duration Indices: Average number of occurrences and duration of interruptions per time period.

The basic elements used to evaluate generation adequacy are shown in Figure 2.10 where generation and load data and model parameters are taken and simulated using deterministic or probabilistic tools to verify the amount of generation versus load demand, which are further utilized to evaluate reliability indices like: LOLP (Loss Of Load Probability), LOLE (Loss Of Load Expectation), EENS (Expected Energy Not Supplied) and IEAR (Interrupted Energy Assessment Rate).

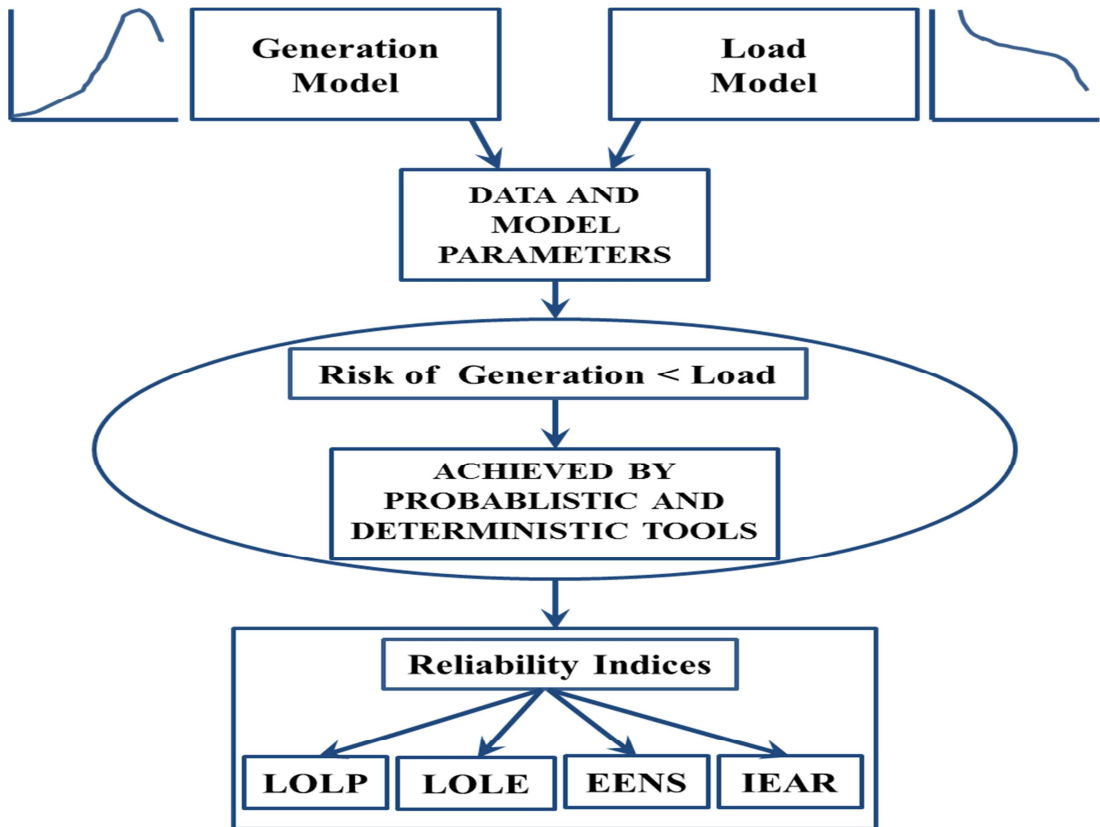


Figure 2.10: The basic elements used to evaluate generation adequacy

Source: Billinton and Allan 1984.

An outage may or may not cause an interruption of service depending on the margins of generation provided. Outages also occur when the unit undergoes maintenance or other scheduled work necessary to keep it operating in good condition.

- A *forced outage* is an outage that results from emergency conditions, requiring the component to be taken out of service immediately.
- A *scheduled outage* is an outage that results when a component is deliberately taken out of service, usually for the purposes of preventive maintenance or repair.

A hierarchical representation of said states is shown in Figure 2.11

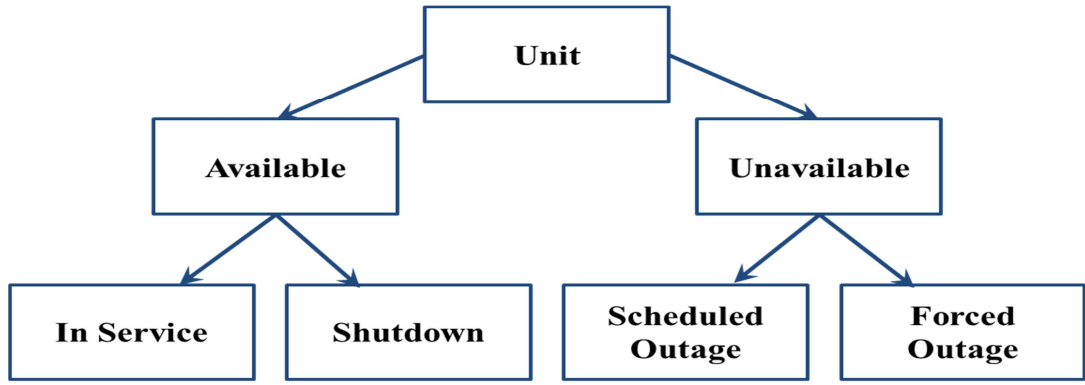


Figure 2.11: A Hierarchical representation of different operating states

Source: Billinton and Allan 1984.

$$U = \frac{\Sigma[\text{down time}]}{\Sigma[\text{down time}] + \Sigma[\text{up time}]} \quad (2.14)$$

$$U = \frac{\lambda}{\lambda + \mu} = \frac{r}{m + r} \quad (2.15)$$

Where,

λ = unit failure rate, μ = unit repair rate

m = mean time to failure = $\frac{1}{\lambda}$, r = mean time to repair = $\frac{1}{\mu}$

$T = m + r$ = mean cycle time, $f = \frac{1}{T}$ cycle frequency = $\mu \cdot U$

The unit unavailability is commonly referred to as the ‘Forced Outage Rate’ (*FOR*), which in fact is not a rate but the ratio of two time values. If computed over a long period of time, the *FOR* is equivalent to unit unavailability. Models with multiple states can be used to represent partial outages as de-rated states. Multistate models are also useful to accommodate intermittent operation and start-up failure rates. Of course, the level of detail of the model depends on the degree of accuracy sought. In most reserve studies the two-state representation is sufficient.

$$FOR = \frac{\text{forced outage hours}}{\text{in service hours} + \text{forced outage hours}} \quad (2.16)$$

2.7.7.1 Loss of Load Reliability Index

A loss of load will occur whenever the system load exceeds the generating capacity in service. The overall probability of this happening is called the Loss-of-Load Probability or LOLP. For an expected load L and available generation capacity C_A , the LOLP is:

$$LOLP = \sum_j P[C_A = C_j] \cdot P[L > C_j] \quad (2.17)$$

Source: Billinton and Allan 1984.

The simplest case is when the load is constant and known. If ' L_o ' is the expected load, the loss-of-load probability will be the probability of all the outage events leaving the system with an available capacity lower than ' L_o ':

$$LOLP = \sum_j P[L_o > C_j] \quad (2.18)$$

Source: Billinton and Allan 1984.

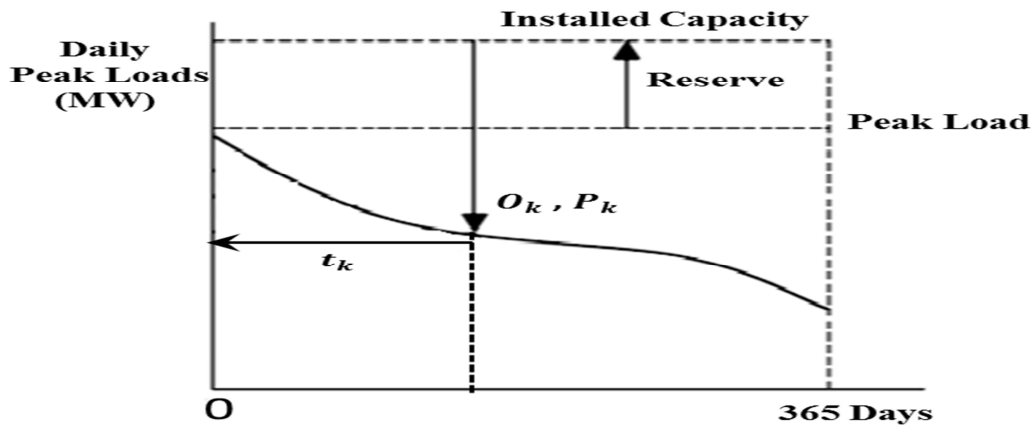


Figure 2.12: The LOLP calculation with a daily Peak Load Curve

Source: Billinton and Allan 1984.

The LOLP can be used to measure loss-of-load risk per hour or just consider the expected peak load during the dispatch period. For long-run and installed capacity evaluation, a cumulative load curve is used.

The LOLP calculation is illustrated in Figure 2.12 with a daily peak load curve. ‘ Ok ’ is the magnitude of the ‘ k^{th} ’ outage in the system, ‘ p_k ’ is the probability of a capacity outage of magnitude ‘ Ok ’, and ‘ t_k ’ is the number of days that an outage of magnitude ‘ Ok ’ would cause a loss of load in the system.

The system LOLP for the period is:

$$LOLP = \sum_k p_k t_k \quad (2.19)$$

Source: Billinton and Allan 1984.

2.7.7.2 Loss of Energy Reliability Index

The loss-of-energy method is a variation of the loss-of-load method. Here the measure of interest is the ratio of expected non-served energy to total energy demand over a period of time. If ‘ Ek ’ is the energy not supplied due to a capacity outage ‘ Ok ’, and ‘ E ’ is the total energy demand during the period of study, the Loss-of-Energy Probability (LOEP) is given by the following ratio:

$$LOEP = \sum_k \frac{E_k p_k}{E} \quad (2.20)$$

Source: Billinton and Allan 1984.

It is also known as the Loss-of-Energy Expectation LOEE. Again, the simplest case is when the load is constant and known. If L_o is the expected load during say 1h, the energy demanded is $E_o = L_o \times 1\text{h}$ (MWh), and the system loss-of energy probability during the hour will be:

$$LOEP = \sum_j \frac{E_j p_j}{E_o} \approx \sum_j \frac{(L_o - C_j) \cdot p(C_j)}{L_o} \quad \text{for } L_o > C_j \quad (2.21)$$

Source: Billinton and Allan 1984.

For longer periods and installed capacity evaluation the load duration curve is used. Any capacity outage exceeding the reserve will result in load interruption and energy curtailment. The non-served energy is the shaded area observed in Figure 2.13

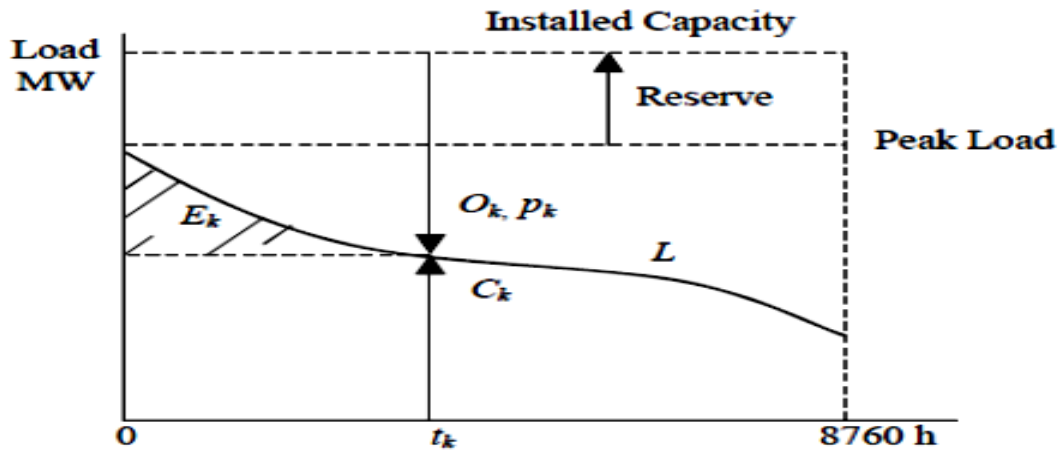


Figure 2.13: Load Duration Curve for calculating Non-Served Energy

Source: Billinton and Allan 1984.

2.7.7.3 Economic Indices for Reliability

Sector Customer Damage Function: SCDF

Composite Customer Damage Function: $CCDF = \sum L_{ave\ i} * SCDF$ (2.22)

Expected Customer Outage Cost: $ECOST = \sum CCDF(r)$ (2.23)

Interrupted Energy Amount Rate: $IEAR = ECOST/EENS$ (2.24)

Expected Energy Not Supplied: $EENS = \sum L_{ave\ i} * r_i$ (2.25)

Where,

$L_{ave\ i} \rightarrow$ Average load of customers interrupted by outage 'i'

$r_i \rightarrow$ Duration of interruption to customers due to outage 'i'

Power Systems Engineering Committee (1978 p.1097-1103) suggested that for quantitative assessment of the power system reliability, the indices required should provide the information related to failures based on frequency and probability.

2.7.8 CLASSIFICATION OF RELIABILITY INDICES

Reliability indices for adequacy assessment may be classified generally under the categories of Probability, Frequency, Duration, and Expectation.

Probability Indices measures risk (or assurance) under specified configurations, load, time and conditions with timespan. For example, the risk of insufficient capacity reserve at annual peak load is a probability index.

Example: $P \{ \text{insufficient capacity reserve at annual peak} \} = 0.001$

Frequency Indices measures the expected rate of recurrence of specific events per unit of time.

Example: Frequency of capacity deficiency = 0.2 events/year

Duration Indices are employed to indicate the expected time in residence in a specific state; i.e. load and configuration.

Example: Average duration of capacity deficiency = 0.25 days

Expectation Indices are formed from the average or expected value of a random variable such as reserve deficiency or interrupted load. Let C be the available capacity, and let $p_C(C)$ be the probability density function for the random occurrence of C . For a given load (L) the expected capacity deficiency would be given by

$$E \{ \text{Cap. Deficiency} \} = \int_{C=0}^{C=L} (L - C) P_C(C) dC \quad \text{MW} \quad (2.26)$$

These indices are by themselves mono-parametric indices; i.e., the indices employ a single statistical parameter. Bi-parametric indices are expressed by two statistical parameters. As an example, a frequency and duration index provide the following information concerning the occurrence of various capacity system states.

Frequency: The average rate at which a specific rate is encountered.

Average Duration: The average residence time in a specific state.

Mello, Pereira (1994 p.243-248) suggest that almost all the reliability evaluation techniques considers the failure and repair time distribution to be exponential for calculating the reliability indices, which proves erroneous specifically in repair time

evaluation. To improve the decision making not only the averages but also the corresponding probability distribution is supposed to be considered in a reliability evaluation algorithm for better calculation of reliability indices.

2.7.9 OUTAGE COST STUDY

Lu and Dong (2005) suggested the transmission system expansion planning method considering the reliability factor. They did this by minimising the EENS, investment cost and maximising the benefit cost ratio ' λ '. They used a Genetic Algorithm for optimising the multi objective problem. Customer outage cost and CCDF are used for determining the reliability worth. Risk analysis has been conducted by using Minimax regret criterion (Miranda and Proenca 1998 p. 643-648 and 1038-1043).

Billinton and Wangdee (2006 p.345-352) calculates EENS, IEAR, Customer Interruption Cost (CIC) and Cost Per Interruption (CPI) $CPI = \frac{CIC}{FLC}$ at delivery points in a composite Power System, where FLC is the Frequency of Load Curtailment. They suggest that the load shedding policy slightly affects overall system policies rather than the indices related to reliability worth.

According to Alvehag, Söder (2012) evaluation of customer interruption cost depends upon different factors like duration, time and sectors. Time sequence Monte Carlo simulation has been developed to calculate the benefit to the customers due to increase in reliability standards. Seven different cost models have been compared for customer interruption cost evaluation to understand and show how the different type of cost models affects the cost benefit analysis.

Reliability standards for supplying electrical services have to be evaluated in terms of capital cost, in order to achieve the levels of reliability and investment cost. To do

that the Expected Interruption Cost (EIC) has to be calculated. To calculate the worth of reliability the Customer Interruption Cost (CIC) index is calculated and used.

According to (Wacker, Billinton 1989), a wide range of methodologies have been proposed till now for the estimation of customer interruption cost. Not a single method presented till now is universally considered to be appropriate for a particular case and for particular outage conditions.

Manikya Rao.J, Prasad.P.V.N. et al. (August 2010) have used the analytical technique to calculate EENS, ECOST and IEAR for the evaluation of reliability worth in Radial distribution system. They explain that there is always a mismatch between economics and reliability in electrical power system, as the price that the customer is willing to pay is directly proportional to the cost of damage occurred due to the interruption. Some customers are willing to pay more for the higher reliability but some do not agree. Due to the increased competition in the electrical industry, utilities want to provide high level of reliability to the customers with no extra cost.

Eassa, Elnahass and Attia (2007 p.226) developed a philosophy in collection of system and components outage data. To do the valuation of interruption cost in a simple way the customer outage model is evaluated and the customer damage function is calculated for a distribution network. The quantitative analysis of reliability is undertaken in order to have proper planning, design and operation of system. Consistent data collection and continuous monitoring is required to have effective reliable operations of a power system. An important event which causes interruption should be surveyed. Acquired and innate factors should be considered during analysis. The effect of interruption can be divided into direct versus indirect and economic versus social.

The analysis is performed considering two stages:

1. Outage cost model: achieved by classifying customers in different categories.
2. Outage cost estimation: achieved by surveying in different zones.

(Wacker, Billinton 1989) proposed that the customer survey approach is the most reliable and practical way to evaluate the outage cost.

2.7.9.1 Customer Damage Function

Customer Damage Function is calculated by collecting the raw data from the surveys, and then by categorizing it into different groups, which is finally normalized considering specific customer parameters, either using yearly peak demand or yearly energy consumption. The SCDF is calculated which is used to form the damage function for individual customers or group of customers and then CCDF is calculated from above indices.

$$CCDF(t) = \sum_{i=1}^n \frac{W_i * SCDF_i(t)}{LF_i} \$/kW_{avg} \quad (2.27)$$

Where,

i : customer type.

n : number of each customer type.

W_i : energy consumption of customer type i.

$SCDF_i$: sector customer damage function of customer type i.

LF_i : load factor of customer type i.

Outage studies and customer damage models are necessary for determining the reliability worth calculations.

Interrupted Energy Rate (IER)

$$IER = \frac{\sum_{k=1}^n CCDF(t_k) * p_k}{\sum_k t_k * p_k} \text{ \$/kWh} \quad (2.28)$$

$$ICPE = \frac{\text{Interruption Cost}}{\text{Number of Outage Events}} \\ = \frac{\sum_{k=1}^n CCDF(t_k) * p_k}{\sum_k k} \text{ \$/event} \quad (2.29)$$

Where,

CCDF: Composite Customer Damage Function.

t_k : interruption duration of k^{th} interruption.

p_k : load loss of k^{th} interruption.

n : number of interruptions. $W_i * SCDF_i(t) n$

Eassa (2011 p.0116) describes the method for minimising the investment cost and customer damage cost to achieve system reliability because inadequate reliability costs the consumers more than good reliability.

The CDF (Customer Damage Function) is a function of interruption duration, frequency, lost load, location and other social effects.

The system installation cost is deterministic in nature and can be evaluated by established methods.

The CDC (Customer Damage Cost) calculations are necessary but quite a difficult task to accomplish while undertaking reliability analysis. The CDC can be evaluated using the survey conducted. CDF gives the details of interruption costs versus interruption duration for a group of customers.

CCDF gives the total interruption cost, which is a function of the interruption duration for the combined customers in a service area.

Hirve and Deshmukh (2013, p.151-156) describe the calculation of Reliability worth using Customer Interruption Cost (CIC) assessment at respective system load points. Reliability worth is the requirement of the capital to be invested to obtain the optimum level of adequacy and security.

Poore, Greene et al. (1983) suggested a procedure for determining the customer interruption cost using a frequency and duration method that can be applied to the generation system reliability evaluation.

Manikya, Prasad and Tulasi (2010 pp.88-96) suggested that the level of supply reliability can be quantified and calculated as Expected Interruption Cost (EIC). The switching devices affect the interruption duration and hence the interruption cost as well.

According to Dalabeeh and Al-Hajbi (2014, p.45-55) the reliability of a system is affected by an additional line at different position for the same capacity and demand. The Simplex method has been used to determine the reliability worth.

According to Bhavajaru et al. (1988 p.149-157) the model for evaluating composite system reliability should include,

1. Static assessment capability for composite system.
2. Monitoring of the system capability with problems and also the remedial action required.
3. DC and AC load flow solutions.
4. Line limits considering both thermal and angle limits.
5. Transformer limits for contingency load carrying limits.
6. Dispatch capability considering security constraints.
7. Seasonal and discrete load levels to be considered in the load modelling.

8. Line and transformer outages due to weather and station originated disturbances.
9. Maintenance schedule for the generators.
10. Multiple capacity state model for generating units and outages.

Ghajar and Billinton (2006 p.29-35) developed a methodology to calculate CDF and IEAR at individual load points in the entire system.

IEAR are the factors that relate customer's losses due to the power interruption with the reliability worth which is developed for HL-I (Billinton, Oteng-Adjei and Ghajar 1987 p. 53) and composite power system (Oteng-Adjei and Billinton, 1990 p. 1317-1323). IEAR value has been calculated that can be used for the expansion studies and reliability worth calculation.

According to Wacker, Billinton (1989) the worth of the electrical supply reliability is much complicated and its evaluation is not that easy, but it is obligatory. The value of reliability can be directly evaluated by designing an appropriate demand function, and the cost at which it is been delivered. Manikya Rao.J, Prasad.P.V.N. et al. (August 2010) have suggested that willingness to pay is one of the foundations for reliability evaluation. But Wacker, Billinton (1989) suggested that it cannot be the only appropriate method for evaluation, the reason being is if the client is asked about their willingness, there are chances that the important customers will rather think emotionally than judge logically and finding it irrelevant, will change the supplier. Another case can be the consumers' willingness to pay less than the actual value of the service, which can devalue the cost of providing reliability.

The reliability worth evaluation is carried out at the load points on different locations in the system. Jha, Sinha et al. (2012), Karki, Verma et al. (2010), conducted a

customer survey and presented a paper to determine the outage cost for customers in developing countries (India). They reported that customer surveys are more popular in developed countries and no major advancement has been achieved there regarding the same. They further emphasize the importance of determining the customer outage cost for calculating the worth of reliability and it is considered to be an indirect indicator for determining the actual cost of monetary loss to the customers. They further suggested that the calculation of outage cost can be achieved by taking a ratio of cost of energy not served to the Loss of Load Expectations (LOLE).

Lvovs, Mutule (2012) has suggested the importance of time varying load over the constant loads in determining the outage cost for the customers. According to the author the loads keep changing during the course of the year and the interruption time also varies depending upon seasonal variations. So in order to determine the customer cost of reliability more accurately time variable loads should be taken into account for calculations. It has been suggested that the above proposed calculations can only be carried out if the outage cost variation in time and load of the system is known.

Crozier, Wisdom (1999) quoted that the price is an economic sacrifice a customer makes to acquire a product or a service and therefore he always compares his sacrifice with his perception of the product value. In their paper they emphasize that the improved Power Quality and Reliability (PQ&R) index is incorporated in order to give a positive impact on the customer benefits due to power outage. The value based PQ&R index can be a ratio of interruption cost of a supplier's customers and its KWh sales.

According to Goel, Billinton (1991) reliability worth evaluation is the estimation of the cost in relation to the diverse setup of the system and its reliability cost at the end of customers.

2.8 SUMMARY

Current research on Transmission pricing, congestion pricing and reliability evaluation is vast and most of the researchers base their implementations on previous work, to improve the pricing scheme of the system. Most of the work is carried out in parts e.g. either transmission pricing alone or reliability evaluation. A combined work for a whole system analysis is missing. The customer of transmission network faces congestion price uncertainty. Minghai Liu, Gross (2004) used PTDF to evaluate the sensitivity of active power flows and suggested that they can also be used to set the congestion prices. India is presently suffering from high transmission and distribution losses and is unable to recover the revenue for the energy supplied. So a new pricing methodology becomes a necessity. Similarly the reliability factor is not properly implemented in the transmission system and therefore the methodology is required which makes the operation of transmission system more reliable and also helps in making revenues for the reliability provided in the transmission system. These are some of the findings in brief from the surveyed literature.

The reason for conducting a literature review of

1. ATC,
2. Congestion Pricing,
3. Distribution factors,
4. Transmission Pricing and

5. Reliability evaluation

is because after the initial review it became obvious that for a DMF and ROTC as stated in the aims and objectives, to be an integrated holistic solution involving methods from each of the above it would be necessary to evaluate and present an approach which can be applicable for any particular region or a country.

The findings and research gaps found from the Literature review are,

- PTDF has never been used for estimating the congestion cost but it has been recommended that it can be used to do the same.
- The new Transmission pricing method is in process to be implemented throughout India, so an ideal transmission pricing method which is easy to implement and will also provide sufficient revenues to the Transmission Company is suggested.
- A justified reliability pricing scheme is suggested which will improve the system efficiency and helps in the economic growth of the transmission network.
- All of the above mentioned components have not been analysed together, so a complete analysis will provide a justified overview of the whole process and its economic viability.

In conclusion the review has identified the gaps that had to be investigated with appropriate solutions devised in order to create a Meta-Analytical Probabilistic Approach based DMF for ROTC. This has been devised and evaluated on an Indian network as detailed in parts 3, 4 and 5.

PART-2

1. METHODOLOGY

CHAPTER – 3

3.1 METHODOLOGY: INTRODUCTION

In this chapter a brief but comprehensive overview of the methodology utilised to achieve the aim and the objectives will be undertaken. First we will revisit the objectives and then briefly explain how these were achieved, and then give a detailed flowchart for a comprehensive overview followed by detailed explanations of each part in the following chapters.

3.2 THESIS OBJECTIVES

The objectives of this thesis are summarized here as follows:

1. To estimate the Congestion Costing using Bialek's method and the newly developed application of PTDF method and to compare the viability of the proposed method.

This objective was achieved by developing the mathematical derivations for the Bialek's and the proposed application of PTDF methods and implementing these in MATLAB programming codes for each method. Both the above mentioned methods were further compared for the congestion cost and verification undertaken for the obtained results with Bialek's method to compare and demonstrate the advantage of the proposed method over Bialek's method. The detailed process, implementation and the results for achieving this objective are given in Chapter 6 and the relevant codes in Appendix.D, where it has been exemplified with the relevant case studies.

2. To estimate Transmission Costing using three MW-Mile methods, Bialek's method and the developed application of PTDF method, their comparison and justification related to the proposed method.

This objective was achieved by developing the mathematical derivations for for the MW-Mile, Bialek's and the proposed application of PTDF methods and forming MATLAB programming codes for each method. All the methods were further compared for the transmission cost and verification is done for the obtained results with MW-Mile and Bialek's method and explaining the advantage of the proposed method over MW-Mile and Bialek's method. The detailed process, implementation and the results for achieving this objective are given in Chapter 5 and the relevant codes in Appendix.D, where it has been exemplified with the relevant case studies.

3. To evaluate Reliability using Probabilistic methods i.e. Monte Carlo simulation method in which Variance Reduction Techniques (VRT) such as, Simple Sampling and Importance Sampling; and Time Sequential Approach are used for estimation of EENS and ECOST index.

This objective was achieved by developing the mathematical derivations for the Monte Carlo simulation methods and implementing these in MATLAB programming codes for these methods. Simple Sampling and Importance Sampling (VRT) methods were further compared for the EENS and verification is done for the obtained results using coefficient of variance and explaining the advantage of one method over another. The detailed process, implementation and the results for achieving this objective are given in

Chapter 7 and the relevant codes in Appendix.D, where it is been exemplified with the relevant case studies.

4. Integration of all costs obtained by the proposed MAPA to form a ROTC.

This objective was achieved by developing the mathematical derivations considering the load contributions on transmission and congestion cost using the proposed application of PTDF method and integrating the costs obtained from congestion, transmission cost for the transmission system and also the reliability cost value for the small radial distribution system attached to the 7th bus of the standard 7-Bus system. The detailed process, implementation and the results for achieving this objective are given in Chapter 7 and the relevant codes in Appendix.D, where it has been exemplified with the relevant case studies.

3.3 METHODOLOGY

3.3.1 OVERVIEW

In the context of research work, a new method consisting of DMF for ROTC has been developed to find the Reliability benefits reflective Optimal Transmission Cost including congestion costing using PTDF. The detailed procedure to find PTDF and the process to find Congestion and Transmission costing considering Generator and Load contribution for Line flows is illustrated in Chapter 6. The philosophy of the new method is that PTDF, which was suggested and used as a sensitivity factor (Minghai Liu, Gross 2004) in Power System, can be used to determine the Generator and Load contribution for Power Flow in transmission line. These contributions can further be utilised to calculate the Congestion and Transmission Costing considering

steady state thermal and voltage constraints in the system. The line limit constraint for calculation of Congestion Cost has been used.

For analysis, the proposed method is tested with three different systems;

1. 7-Bus,
2. IEEE 30-Bus and
3. Indian Utility 146-Bus system.

The proposed application of PTDF method is compared with Bialek's method and MW-Mile methods in Transmission costing and Bialek's method in congestion costing for all the three chosen test systems.

For Reliability worth analysis a small distribution network is considered which is connected to the 7th bus of the 7-Bus (M, H 2015) transmission system in which reliability data is taken from the paper by (Billinton, Li 1994). For estimation of Reliability worth Monte Carlo Simulation is used in which Variance Reduction Methods (Simple Sampling & Importance Sampling) are used to determine EENS for the system and at each Bus. And for ECOST calculation, a time sequential approach for Monte Carlo method is used. ECOST and EENS determined at a Bus where the Distribution Load is assumed to be attached is then summed up with the transmission cost and congestion cost at that Bus, which is the optimal Transmission Costing for transmitting that much power to that bus using Reliability Benefits.

3.3.2 META-ANALYTICAL PROBABLISTIC APPROACH (MAPA)

The meta-analysis is a combined analysis acquired from different methods by contrasting and combining results achieved.

In this research, the developed approach is called MAPA as different power system process like congestion, transmission and reliability methods are analysed to formulate our work, and come up with a new transmission and congestion cost evaluation method which also includes probabilistic analysis. Congestion and transmission costing with reliability benefits value have also been integrated to devise and construct a DMF for ROTC.

The steps that have used for the MAPA can be stated as follows:

1. Problem formulation
2. Literature review
3. Methods selection for analysis
4. Proposed method development
5. MATLAB programming codes development for results and their comparison with other selected methods for analysis.

3.4 FLOW CHART PRESENTING OVERVIEW OF DMF AND MAPA

In the Flow Chart shown in Figure 3.1 the Decision Making Framework (DMF) and Meta-Analytical Probabilistic Approach (MAPA) for the determination of ROTC has been explained.

As seen from the flow chart, all the data such as: Bus data, Line data, Generator data, Reliability data and Customer Damage Function (CDF) data are being used in different analytical and probabilistic methods i.e. MAPA, for the evaluation of Congestion Costing, Transmission Costing and Reliability Worth of the Transmission System. The obtained results of all the cost obtained using different methods are compared and analysed in the DMF and then considering the demand

and socio-economic fitness of the costing method in the particular state / country, the methods are selected for Congestion Costing, Transmission Costing and Reliability worth, which are then integrated to form a ROTC.

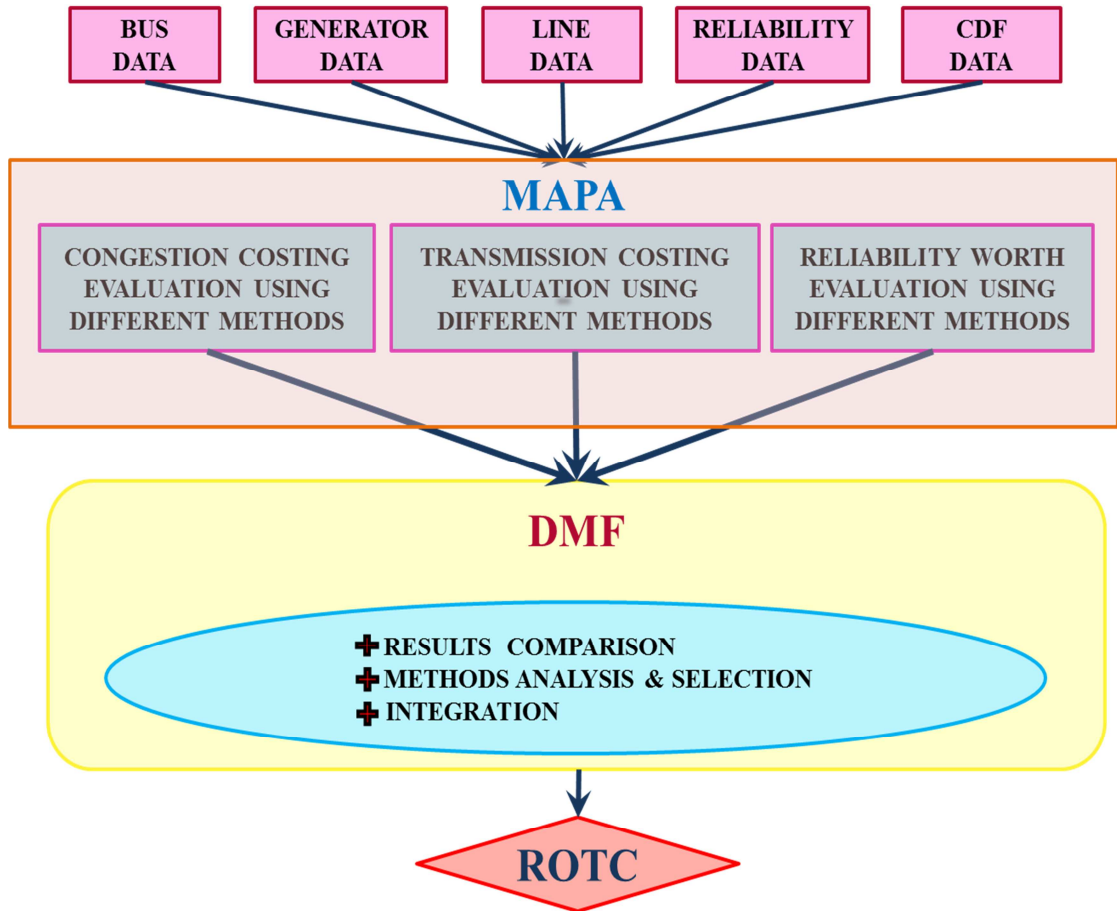


Figure 3.1: Flow chart showing overview of DMF and MAPA.

3.5 FLOW CHART FOR OVERVIEW OF THE METHODOLOGY

The Flow Chart shown in Figure 3.2 describes the Optimal Transmission Costing Methodology used for determining the ROTC for this research study in brief.

The highlighted parts of the methodology shown in the flow chart explains that

1. Generation and transmission data is utilised for conducting AC load flow using Newton-Raphson method, which serves as the load flow engine and data base in the flow chart.

OPTIMAL TRANSMISSION COSTING METHODOLOGY

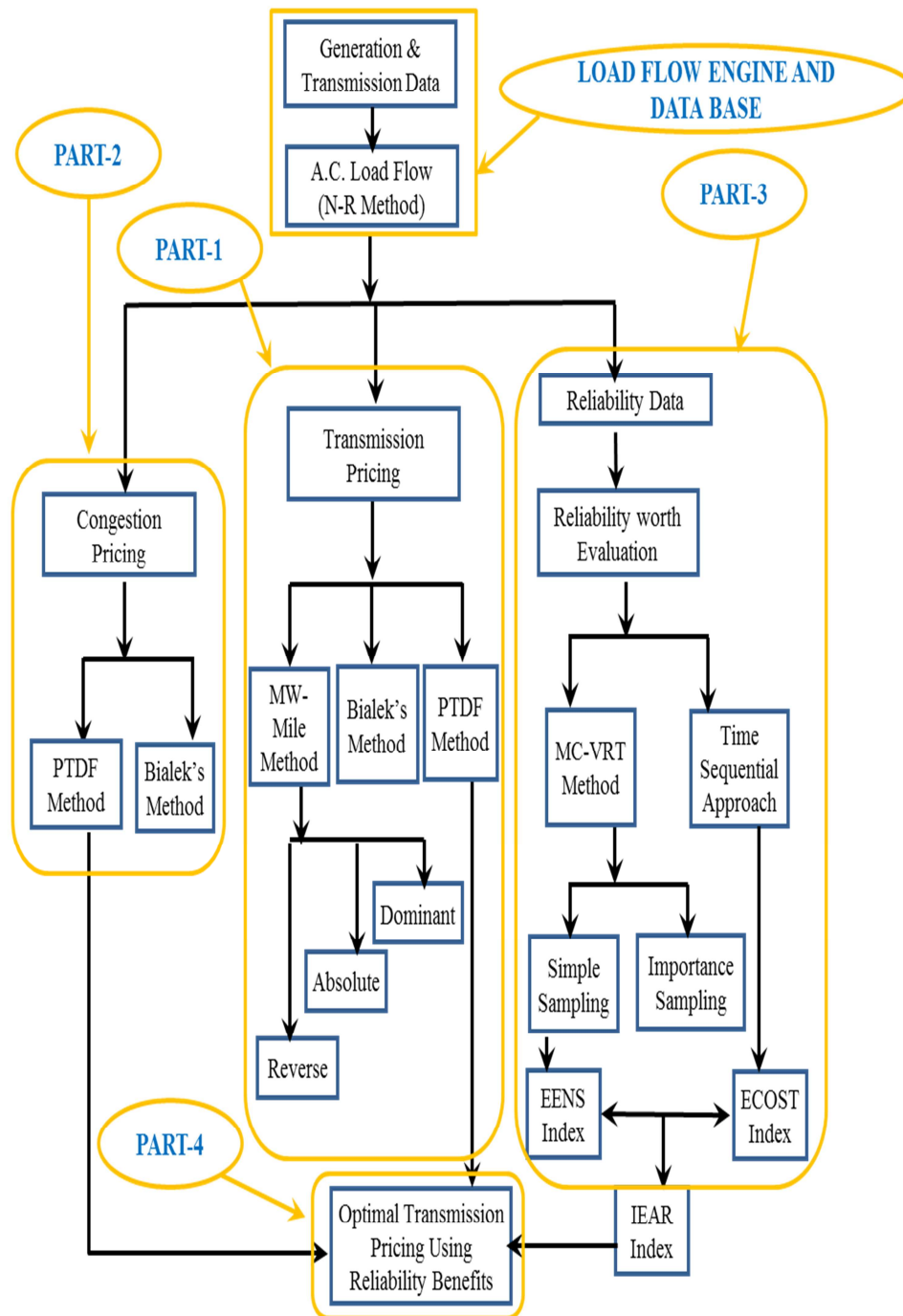


Figure 3.2: Flow chart showing Optimal Transmission Costing Methodology.

2. Transmission costing is conducted using MW-Mile, Bialek's and the proposed application of PTDF pricing method and then they are compared for verification of the proposed application of PTDF method and its implementation for suggested ROTC, which is shown as Part-1 in the flow chart.
3. Congestion costing is conducted using Bialek's and the proposed application of PTDF pricing method and then they are compared for verification of the proposed application of PTDF method and its implementation for suggested ROTC, which is shown as Part-2 in the flow chart.
4. Reliability worth evaluation is conducted considering a small radial distribution system attached to one of the buses of a transmission system as a load and using the reliability data for that distribution system in formulating Matlab codes for MC-VRT and Time sequential approach. Simple and importance sampling are then compared for verification and determination of EENS, ECOST and IEAR which are then used in the implementation of the suggested ROTC, which is shown as Part-3 in the flow chart.
5. The integration of all the parts in the devised DMF is conducted in part-4 shown in the flow chart, which is the final part of the DMF for ROTC.

For analysing and estimating the results MATLAB programming codes for each section have been developed, which along with the available data is used to calculate the ROTC. The developed MATLAB program is shown in Appendix D.

3.6 POWER TRANSFER DISTRIBUTION FACTORS CALCULATION

Power Transfer Distribution Factors (PTDF) shows the linear impact of power transfer i.e. it gives the percentage of power transfer in each transmission line of a power system. It can be calculated using power flow jacobians.

Consider a transaction ' P_{mn} ' between a seller bus ' m ' and buyer bus ' n '. Further consider a line ' l ' carrying a part of the transaction power. Let the line be connected between a bus ' i ' and a bus ' j '. For a change in real power transaction between the above seller and buyer say by ΔP_{mn} , if the change in transmission line quantity ' P_{ij} ' is ΔP_{ij} , the Power Transfer Distribution Factors can be defined as:

$$PTDF_{ij,mn} = \frac{\Delta P_{ij}}{\Delta P_{mn}} \quad (3.1)$$

For power deliveries and for system operations it is important to know that the intensity of current in each branches of the meshed network is inversely proportional to the branch resistance. The PTDF can also be evaluated using physical parameters like reactance (X) or Susceptance ($B = 1/X$) as:

$$PTDF = B^{-1} * B_f \quad (3.2)$$

Where,

B^{-1} : reduced inverse of nodal Susceptance matrix

B_f : reduced branch Susceptance matrix

Reduced means, the rows and columns corresponding to a reference node are eliminated.

Using Power Flow Jacobians PTDF can be derived as follows:

For Power Transfer Distribution Factor calculation using AC Load Flow approach, the power flow sensitivity and Jacobian of power injection equations is required. The

Jacobian can be calculated using N-R load flow based approach. The power flow equations in polar form can be represented as:

$$P_i = \sum_{j=1}^n |V_i| |V_j| |Y_{ij}| \cos(\theta_{ij} - \delta_i + \delta_j) \quad (3.3)$$

$$Q_i = \sum_{j=1}^n |V_i| |V_j| |Y_{ij}| \sin(\theta_{ij} - \delta_i + \delta_j) \quad (3.4)$$

Where 'n' be the total number of buses P_i and Q_i are the real and reactive power injected at any bus 'i'. $|V_i|$, $|V_j|$ are the voltage magnitudes at the buses respectively, δ_i , δ_j are the voltage angles at the buses 'i' and bus 'j', and $|Y_{ij}|$, θ_{ij} are taken from Y_{bus} .

Using Taylor series expansion, the change in power flows at any bus can be formulated in terms of Jacobian as:

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J_1 & J_2 \\ J_3 & J_4 \end{bmatrix} \begin{bmatrix} \Delta \delta \\ \delta |V| \end{bmatrix} \quad (3.5)$$

The value of Jacobians J_1 , J_2 , J_3 and J_4 are explained more fully in equation 4.8, 4.11, 4.13, 4.15 and 4.17 of Chapter 4.

The change in the angle and voltage magnitude can be determined as:

$$\begin{bmatrix} \Delta \delta \\ \delta |V| \end{bmatrix} = \begin{bmatrix} J_1 & J_2 \\ J_3 & J_4 \end{bmatrix}^{-1} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \quad (3.6)$$

Using N-R load flow analysis bus voltage magnitudes and angles can be evaluated. For calculation of Power Transfer Distribution Factors, the Jacobian and power flow sensitivity can be calculated. The power flow sensitivity can be determined using the power flow equations for real power.

The real power flow ' P_{ij} ' in a line 'k', connected between buses 'i' and 'j', can be written as:

$$P_{ij} = V_i V_j Y_{ij} \cos(\theta_{ij} - \delta_i + \delta_j) - V_i^2 Y_{ij} \cos(\theta_{ij}) \quad (3.7)$$

Where V_i and δ_j are the voltage magnitude and angle at bus 'i'. Y_{ij} and θ_{ij} are the magnitude and angle of ij^{th} element of Y_{bus} .

Using Taylor's series approximation and ignoring higher order terms, change in real power can be written as:

$$\Delta P_{ij} = \frac{\partial P_{ij}}{\partial \delta_i} \Delta \delta_i + \frac{\partial P_{ij}}{\partial \delta_j} \Delta \delta_j + \frac{\partial P_{ij}}{\partial V_i} \Delta V_i + \frac{\partial P_{ij}}{\partial V_j} \Delta V_j \quad (3.8)$$

The sensitivity coefficients appearing in (7) can be obtained using the partial derivatives of real power flow in terms of J_1 , J_2 , J_3 and J_4 , with respect to variables ' δ ' and ' V '.

The sensitivity of power flow equation can be written in compact matrix form as:

$$\Delta P_{ij} = \left[\frac{\partial P_{ij}}{\partial \delta_2}, \dots, \frac{\partial P_{ij}}{\partial \delta_n}, \frac{\partial P_{ij}}{\partial V_{g+1}}, \dots, \frac{\partial P_{ij}}{\partial V_n} \right] \begin{bmatrix} \Delta \delta_i \\ \vdots \\ \Delta \delta_i \\ \Delta |V_{g+1}| \\ \vdots \\ \Delta |V_n| \end{bmatrix} \quad (3.9)$$

Where, $\left[\frac{\partial P_{ij}}{\partial \delta_2}, \dots, \frac{\partial P_{ij}}{\partial \delta_n}, \frac{\partial P_{ij}}{\partial V_{g+1}}, \dots, \frac{\partial P_{ij}}{\partial V_n} \right]$ is line power flow sensitivity

corresponding to angle and voltage magnitude. For a single transaction case between seller bus 'm' and buyer bus 'n', the change in power transactions can be substituted at position of bus 'm' and bus 'n' as:

$$\Delta P_m = +P_t$$

$$\Delta P_n = -P_t$$

$$\Delta P_{ij} = \left[\frac{\partial P_{ij}}{\partial \delta_2}, \dots, \frac{\partial P_{ij}}{\partial \delta_n}, \frac{\partial P_{ij}}{\partial V_{g+1}}, \dots, \frac{\partial P_{ij}}{\partial V_n} \right] [J]^{-1} \begin{bmatrix} 0 \\ \vdots \\ +P_t \\ 0 \\ \vdots \\ -P_t \end{bmatrix} = \text{PTDF} * P_t \quad (3.10)$$

where, $[J]$ is the Jacobian matrix.

So, PTDFs for the transaction between seller bus m to buyer bus n can be represented as:

$$\text{PTDF}_{ij,mn} = \left[\frac{\partial P_{ij}}{\partial \delta_2}, \dots, \frac{\partial P_{ij}}{\partial \delta_n}, \frac{\partial P_{ij}}{\partial V_{g+1}}, \dots, \frac{\partial P_{ij}}{\partial V_n} \right] [J]^{-1} \begin{bmatrix} 0 \\ \vdots \\ +1 \\ 0 \\ \vdots \\ -1 \end{bmatrix} \quad (3.11)$$

Both Jacobian and line flow sensitivity factors are taken without considering any assumptions.

3.7 APPLICATION OF POWER TRANSFER DISTRIBUTION FACTORS

The cost of congestion can be allocated to the Loads using Power Transfer Distribution Factors (PTDF). In this section the proposed application of PTDF in the methodology will be explained using the steps followed and also a flow chart of the whole procedure for achieving the desired results will be shown.

The proposed application of PTDF method been used because it shows the linearized impact of a transfer of power. PTDFs are calculated using Newton-Raphson power flow Suseptance matrix 'B'.

$$\Delta \theta = B^{-1} * \Delta P \quad (3.12)$$

Once $\Delta\theta$ (phase angle) is known then the change in the transmission line flows can be derived. Several elements in ΔP (Power Magnitude) can be modified, in proportion to how the specified generators would participate in the power transfer.

PTDF measures the sensitivity of line MW flows to a MW transfer. Line flows are simply a function of the voltages and angles at its terminal buses. Using the Chain Rule, the PTDF is simply a function of these voltage and angle sensitivities.

The suggested approach for allocating the congestion cost to the load and the line considering the line constraints is explained in steps below:

- A. The load flow is carried out using Newton Rapson full AC load flow.
- B. PTDF matrix is formed using reduced nodal susceptance and branch susceptance matrices.
- C. GSDF is determined by programing in MATLAB using Equation 6.14.
- D. GGDF is computed using PTDF using Equation 6.17.
- E. GLDF is calculated from PTDF considering the load supplied by swing bus using Equation 6.20.
- F. Generation cost is calculated for constrained and unconstrained cases using Generator's cost function provided in Appendix A.
- G. Dividing the total congestion cost between lines using the Relief Cost.
- H. Loads and Generators contribution are calculated using PTDF and Bialek's method.
- I. Total congestion cost is computed taking the difference between constrained and unconstrained cases.
- J. Congestion cost is distributed among the loads according to the contribution of load to lines.

3.8 CONTRIBUTIONS OF THIS THESIS WORK

The principle contributions of this research are as follows:

1. A novel application of PTDF Method, for finding Congestion Costing is developed.
2. The proposed PTDF method application is also used for finding Transmission Costing and its comparison with Bialek's Method proves its viability.
3. Introduction of Reliability based Benefits using Probabilistic Method: Combined evaluation of Transmission Costing using Congestion and Reliability benefits in the Electrical Power System.
4. A composite DMF in the form of a MATLAB program for each section of the research using different analytical and probabilistic methods, to evaluate and estimate the specific objectives required in order to achieve complete ROTC results.

PART-3

1. **LOAD FLOW**
2. **TRANSMISSION COSTING**
3. **CONGESTION COSTING**
4. **RELIABILITY WORTH EVALUATION**

CHAPTER – 4

LOAD FLOW

4.1 INTRODUCTION

In order to design and plan an efficient power system for future modification, the power flow study is an inevitable process. The power flow study provides the information regarding the magnitude of voltage and its phase angle at each bus and also the active and reactive power flow in each part of the system.

The power flow has its importance in estimating the system contingencies and the measures to be taken to modify the system in order to serve an added load in the system.

In transmission planning the power flow studies are utilised for evaluating the effects of peak load on transmission system and also to determine the limits violated during peak and off peak condition in order to find the solutions to overcome that situation. The process of analysing the effect of load and generators individually during transmission is necessary for evaluating the deliverability of generation and load.(Saadat 2002)

Buses are classified in three types: Slack/ Swing Bus, Load Bus and Regulated/ Voltage-controlled Bus. The Swing/Slack Bus is considered as the reference bus where the magnitude and the voltage angle are specified. This bus controls the difference caused by losses in the system between loads and the generated power. The reactive power generated at the slack bus is not taken for analysis. The power loss in the system at every bus is given as:

$$P_{Loss} = \sum_{i=1}^n P_i = \sum_{i=1}^n P_{gi} - \sum_{i=1}^n P_{di} \quad (4.1)$$

Real Power Loss Total Generation Total Load

Load buses are called P-Q buses; where the active and reactive powers are specified.

Voltage angles and magnitudes are not known at these buses.

The regulated buses also known as P-V buses are the generator buses. The voltage magnitude and real power at these buses are specified and controlled, which is performed by the generator exciter. At these buses the voltage angles and reactive power magnitude have to be evaluated. Reactive power limits are specified at these buses.

4.2 NECESSITY OF LOAD FLOW ANALYSIS

In a power system 3-phase AC power (Active and Reactive) flows in a network from generation to load through buses and lines. This flow of power is known as power flow. The study of power flow gives the mathematical idea for evaluating magnitude and phase angles of voltage at different lines and buses under steady state operation. Power Engineers use the load flow analysis for operation and future planning as it is a key process for planning new power systems and adding to existing ones.

Power flow gives the details of power input at all the buses and also through all the interconnected lines. This is useful in estimating the optimal location and capacity of installing a generating station, substation and transmission lines. It helps to maintain the voltage levels under their tolerance limits. It is also useful in controlling the cost of fuel by its extraordinary help in operating the system economically.

4.3 NEWTON RAPHSON LOAD FLOW

Newton-Raphson (N-R) method is the most widely used technique for the load flow solutions as it provides quadratic convergence. As compared to Gauss-Seidel method

of load flow, Newton-Raphson method is more accurate and does not diverge for the bad conditioned problems. It is found that for the large power systems the Newton-Raphson method is more practical and efficient. The system size is not related to the total number of iteration required to get a solution. The power flow equations are expressed in polar form as the power and voltage magnitudes are given for the voltage controlled buses.

Consider an n-bus case for a power system as shown in Figure 4.1.

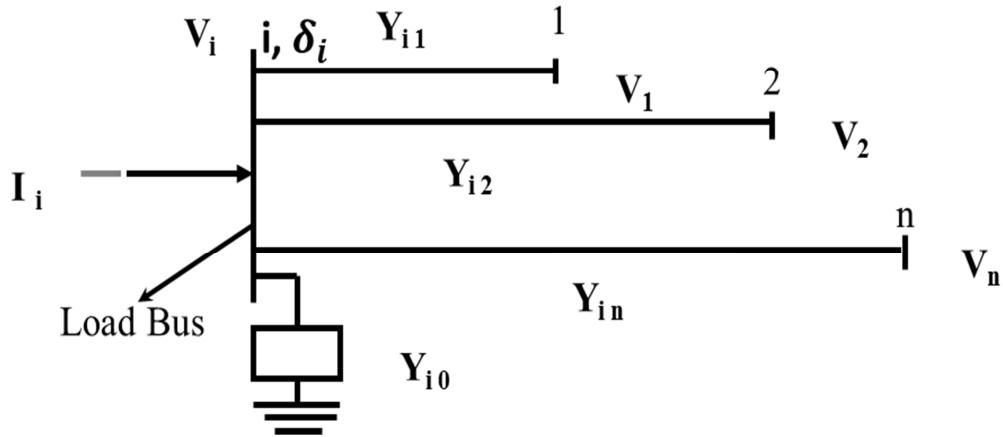


Figure 4.1: N-bus case for a power system

The bus admittance Matrix can be written as:

$$I_i = \sum_{j=1}^n Y_{ij} V_j \quad (4.2)$$

In Polar Form,

$$I_i = \sum_{j=1}^n |Y_{ij}| |V_j| \angle \theta_{ij} + \delta_j \quad (4.3)$$

At Bus 'i' the complex power is,

$$P_i - jQ_i = V_i^* I_i \quad (4.4)$$

By Substituting the value of 'I_i' from equation (4.3) into equation (4.4),

$$P_i - jQ_i = |V_i| \angle -\delta_i \sum_{j=1}^n |Y_{ij}| |V_j| \angle \theta_{ij} + \delta_j \quad (4.5)$$

After separating real and imaginary parts,

$$P_i = \sum_{j=1}^n |V_i| |V_j| |Y_{ij}| \cos(\theta_{ij} - \delta_i + \delta_j) \quad (4.6)$$

$$Q_i = - \sum_{j=1}^n |V_i| |V_j| |Y_{ij}| \sin(\theta_{ij} - \delta_i + \delta_j) \quad (4.7)$$

Equation (4.6) and (4.7) are the nonlinear algebraic equations, where the magnitude of the voltage is in per unit and the angles are in degrees.

For each load bus there are two equations given by equation (4.6) and (4.7).

For each voltage controlled bus the equation will be formed from equation (4.6).

Now after expanding equation (4.6) and (4.7) using Taylor's series for initial estimate and neglecting the higher order terms the result will be the set of linear equations as shown below,

$$\begin{bmatrix} \Delta P_2^{(k)} \\ \vdots \\ \Delta P_n^{(k)} \\ \Delta Q_2^{(k)} \\ \vdots \\ \Delta Q_n^{(k)} \end{bmatrix} = \begin{bmatrix} \frac{\partial P_2^{(k)}}{\partial \delta_2} & \dots & \frac{\partial P_2^{(k)}}{\partial \delta_n} & \frac{\partial P_2^{(k)}}{\partial |V_2|} & \dots & \frac{\partial P_2^{(k)}}{\partial |V_n|} \\ \vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\ \frac{\partial P_n^{(k)}}{\partial \delta_2} & \dots & \frac{\partial P_n^{(k)}}{\partial \delta_n} & \frac{\partial P_n^{(k)}}{\partial |V_2|} & \dots & \frac{\partial P_n^{(k)}}{\partial |V_n|} \\ \frac{\partial Q_2^{(k)}}{\partial \delta_2} & \dots & \frac{\partial Q_2^{(k)}}{\partial \delta_n} & \frac{\partial Q_2^{(k)}}{\partial |V_2|} & \dots & \frac{\partial Q_2^{(k)}}{\partial |V_n|} \\ \vdots & \ddots & \vdots & \vdots & \ddots & \vdots \\ \frac{\partial Q_n^{(k)}}{\partial \delta_2} & \dots & \frac{\partial Q_n^{(k)}}{\partial \delta_n} & \frac{\partial Q_n^{(k)}}{\partial |V_2|} & \dots & \frac{\partial Q_n^{(k)}}{\partial |V_n|} \end{bmatrix} \begin{bmatrix} \Delta \delta_2^{(k)} \\ \vdots \\ \Delta \delta_n^{(k)} \\ \frac{\Delta |V_2^{(k)}|}{|V_2^{(k)}|} \\ \vdots \\ \frac{\Delta |V_n^{(k)}|}{|V_n^{(k)}|} \end{bmatrix} \quad (4.8)$$

Bus 1 is considered as the swing bus. The advantage of the Jacobian matrix is that it provides the linear relationship between any small variation in voltage magnitude and angle with small variation in real and reactive power.

The Jacobian Matrix elements are obtained by taking the partial derivation of equation (4.6) and equation (4.7) evaluated as $\Delta \delta_i^{(k)}$ and $\Delta |V_i^{(k)}|$.

In short form the equation is rewritten as:

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J_1 & J_2 \\ J_3 & J_4 \end{bmatrix} \begin{bmatrix} \Delta \delta \\ \Delta |V| \end{bmatrix} \quad (4.9)$$

For 'm' voltage controlled buses of the system, 'm' equations having ΔQ and ΔV and their corresponding columns are removed from the Jacobian Matrix as the voltage magnitudes for them are known.

There are 'n-1' real power constraints and 'n-1-m' reactive power constraints.

The formed Jacobian matrix will be of order $(2n-2-m) \times (2n-2-m)$ where, J_1 is of order $(n-1) \times (n-1)$, J_2 is of order $(n-1) \times (n-1-m)$, J_3 is of order $(n-1-m) \times (n-1)$, J_4 is of order $(n-1-m) \times (n-1-m)$.

For J_1 the diagonal and off-diagonal elements are,

$$\frac{\partial P_i}{\partial \delta_i} = \sum_{j \neq i} |V_i| |V_j| |Y_{ij}| \sin(\theta_{ij} - \delta_i + \delta_j) \quad (4.10)$$

$$\frac{\partial P_i}{\partial \delta_i} = -|V_i| |V_j| |Y_{ij}| \sin(\theta_{ij} - \delta_i + \delta_j) \text{ where, } j \neq i \quad (4.11)$$

For J_2 the diagonal and off-diagonal elements are,

$$\frac{\partial P_i}{\partial |V_i|} = 2|V_i| |Y_{ii}| \cos \theta_{ii} + \sum_{j \neq i} |V_j| |Y_{ij}| \cos(\theta_{ij} - \delta_i + \delta_j) \quad (4.12)$$

$$\frac{\partial P_i}{\partial |V_j|} = |V_i| |Y_{ij}| \cos(\theta_{ij} - \delta_i + \delta_j) \text{ where, } j \neq i \quad (4.13)$$

For J_3 the diagonal and off-diagonal elements are,

$$\frac{\partial Q_i}{\partial \delta_i} = \sum_{j \neq i} |V_i| |V_j| |Y_{ij}| \cos(\theta_{ij} - \delta_i + \delta_j) \quad (4.14)$$

$$\frac{\partial Q_i}{\partial \delta_i} = -|V_i| |V_j| |Y_{ij}| \cos(\theta_{ij} - \delta_i + \delta_j) \text{ where, } j \neq i \quad (4.15)$$

For J_4 the diagonal and off-diagonal elements are,

$$\frac{\partial Q_i}{\partial |V_i|} = -2|V_i| |Y_{ii}| \sin \theta_{ii} - \sum_{j \neq i} |V_j| |Y_{ij}| \sin(\theta_{ij} - \delta_i + \delta_j) \quad (4.16)$$

$$\frac{\partial Q_i}{\partial |V_j|} = -|V_i| |Y_{ij}| \sin(\theta_{ij} - \delta_i + \delta_j) \text{ where, } j \neq i \quad (4.17)$$

The difference between scheduled and calculated values are given by $\Delta P_i^{(k)}$ and $\Delta Q_i^{(k)}$ which are also known as power residuals, and are expressed as,

$$\Delta P_i^{(k)} = P_i^{sch} - P_i^{(k)} \quad (4.18)$$

$$\Delta Q_i^{(k)} = Q_i^{sch} - Q_i^{(k)} \quad (4.19)$$

For the bus voltages the new estimates will be,

$$\delta_i^{(k+1)} = \delta_i^{(k)} - \Delta \delta_i^{(k)} \quad (4.20)$$

$$|V_i^{(k+1)}| = |V_i^{(k)}| + \Delta |V_i^{(k)}| \quad (4.21)$$

4.4 PROCEDURE FOR CALCULATING STATE VARIABLES

The stepwise procedure for power flow solution using the Newton Raphson method which was used to calculate transmission and congestion costing is explained below:

1. Voltage magnitudes and phase angles are kept equal to the value of swing bus, or 1.0 and 0.0, for the load buses where, P_i^{sch} and Q_i^{sch} are given. i.e. $|V_i^{(0)}| = 1.0$ and $\delta_i^{(0)} = 0$. Phase angles are kept equal to the swing bus angle or 0, for voltage controlled buses where, $|V_i|$ and P_i^{sch} are given. i.e. $\delta_i^{(0)} = 0$.
2. For load buses, $P_i^{(k)}$ and $Q_i^{(k)}$ are evaluated using equations (4.6) and (4.7) and $\Delta P_i^{(k)}$ & $\Delta Q_i^{(k)}$ are evaluated using equations (4.18) and (4.19).
3. For voltage controlled buses, $P_i^{(k)}$ and $\Delta P_i^{(k)}$ are evaluated using equations (4.6) and (4.18).
4. The Jacobian Matrix elements (J_1 , J_2 , J_3 and J_4) are evaluated using equations (4.10) to (4.17).
5. Linear simultaneous equation (4.9) are evaluated by Gaussian elimination and optimally ordered triangular factorization.
6. The new phase angles and voltage magnitudes are evaluated from equation (4.20) and (4.21).
7. The iterations to find the solutions continue until the power residuals $\Delta P_i^{(k)}$ and $\Delta Q_i^{(k)}$ becomes less than the specified accuracy, i.e.

$$|\Delta P_i^{(k)}| \leq \epsilon \text{ and } |\Delta Q_i^{(k)}| \leq \epsilon \quad (4.22)$$

4.5 SYSTEMATIC CODING OF NEWTON-RAPHSON LOAD FLOW IN MATLAB

The MATLAB programming for Newton-Raphson Load Flow is slightly complicated. So systematic and dynamic planning is required. MATLAB is software simulation package which contain some tools that are specifically developed for engineering applications and are available in a tool box which can be used according to specific requirements.

Initially the Load flow using Newton-Raphson method is fully studied and analysed with the main components and variables to consider. Then all the data required for the execution of the developed program is taken care of.

The line data and bus data are stored in separate files with a call function and then the programming to find the admittance matrix is formulated, which is also given with the call function. Finally the programming for Newton-Raphson method is carried out following the above mentioned procedure. In the Newton-Raphson Load Flow programming, bus data, line data and admittance matrix results have been called and utilized to find the complete solution using Newton-Raphson Load Flow. The final result comprises the bus number, its voltage, angle, power injected, power generated, loads, line flow and losses between lines.

The developed Newton-Raphson Load Flow program was first tested with the 7-Bus system. After assuring that the results are correct the programming was further modified for evaluating large transmission systems like the IEEE 30-Bus system and the Indian Utility 146-Bus system.

4.6 FLOW CHART FOR NEWTON-RAPHSON LOAD FLOW

The following Flow Chart in Figure 4.2 explains the process equations used as the basis for programming in MATLAB (Codes are provided in Appendix-D).

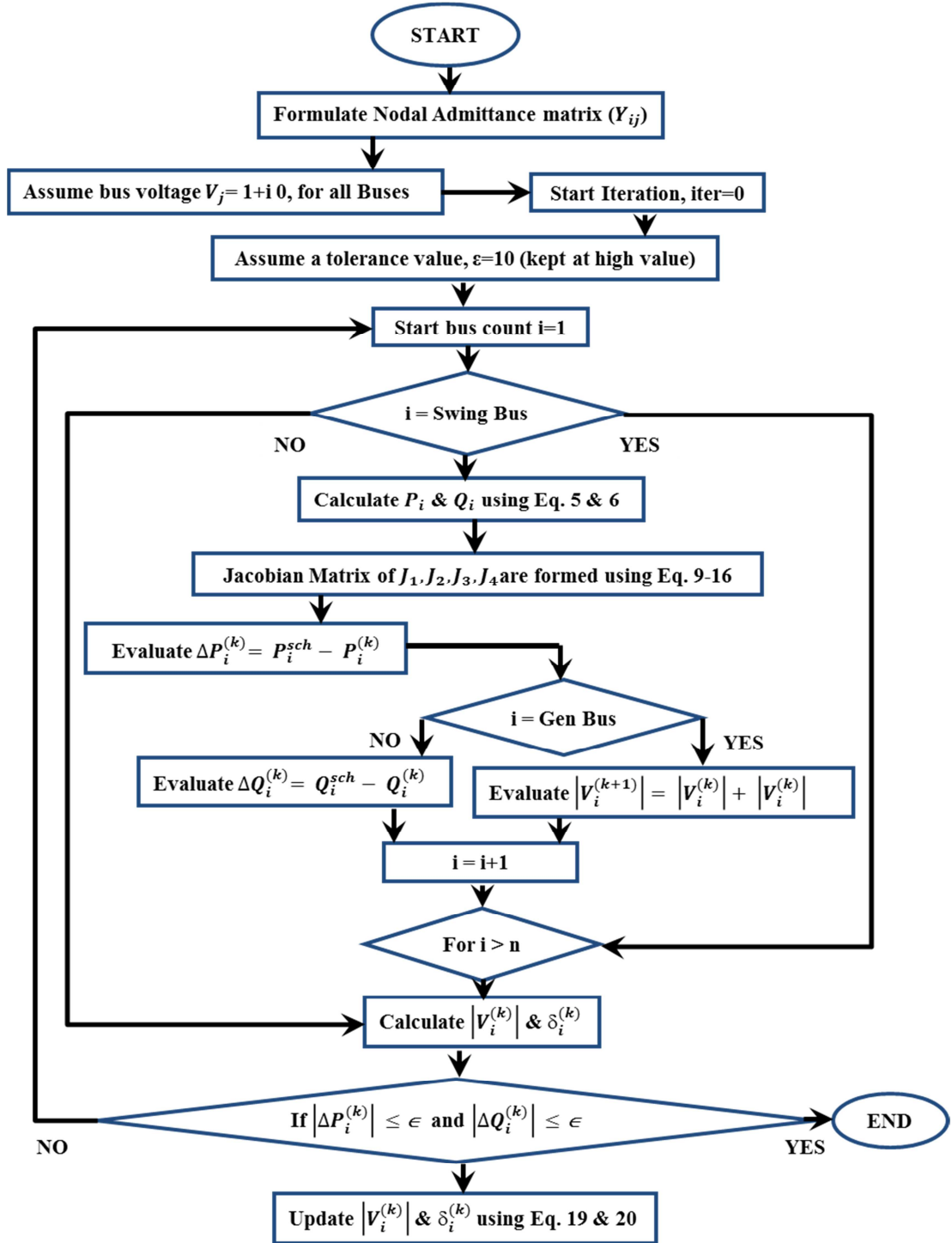


Figure 4.2: Flow Chart for Newton-Raphson Method

4.7 RESULTS

The following results of Load Flow for the 7-Bus case study are given below to verify the output of load flow studies with the published results in literature and these results were used as a part of procedure to calculate ROTC.

4.7.1 7-BUS TEST SYSTEM

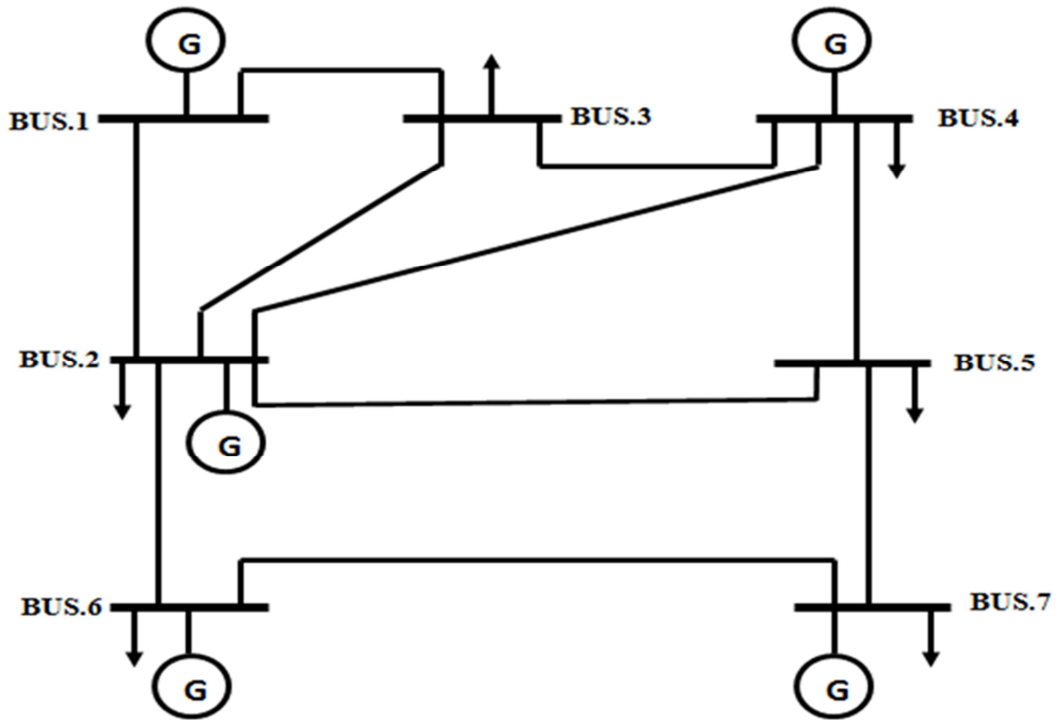


Figure 4.3: One-line Diagram for 7-Bus Transmission System

Source: (Gnanadass 2015)

The 7-Bus test system one-line diagram is shown in Figure 4.3. The generator, bus and line data used for the 7-Bus test system is given in Table A.1, Table A.2 and Table A.3 of Appendix-A.

The results obtained after executing a Newton-Raphson Load flow MATLAB Program using the 7-Bus data are shown below:

Table 4.1: Power Injected, Voltage and Phase angle for 7-Bus (Unconstrained case)

UNCONSTRAINED			POWER INJECTED		POWER GENERATED		LOAD	
BUS No.	VOLTAGE (pu)	ANGLE (Degree)	MW	MVAR	MW	MVAR	MW	MVAR
1	1.05	0.00	283.50	5.56	283.50	5.56	0	0
2	1.02	-7.33	-30.00	24.75	50.00	24.75	80	0
3	1.02	-6.50	-110.00	0.00	0.00	0.00	110	0
4	1.02	-5.34	160.00	-35.09	200.00	-35.09	40	0
5	0.97	-15.32	-130.00	0.00	0.00	0.00	130	0
6	1.00	-10.64	-50.00	-4.67	150.00	-4.67	200	0
7	0.95	-17.42	-110.00	0.60	90.00	0.60	200	0

Table 4.2: Line Flow and Line Loss for 7-Bus (Unconstrained case)

UNCONSTRAINED		LINE FLOW		FROM	TO	LINE FLOW		LINE LOSS		LINE LIMIT
FROM	TO	MW	MVAR			MW	MVAR	MW	MVAR	MW
1	2	231.84	11.09	2	1	-226.95	18.22	4.89	29.32	135
1	3	51.67	6.59	3	1	-50.68	-0.69	0.98	5.91	58
2	3	-7.53	6.00	3	2	7.55	-5.85	0.03	0.16	55
2	4	-18.71	9.19	4	2	18.84	-8.45	0.12	0.74	45
2	5	121.52	11.53	5	2	-118.71	5.33	2.81	16.85	200
2	6	101.67	3.15	6	2	-100.69	2.71	0.98	5.85	130
3	4	-66.87	18.02	4	3	67.10	-16.64	0.23	1.38	40
4	5	74.06	1.45	5	4	-71.95	11.21	2.11	12.66	44
7	5	-60.30	6.68	5	7	60.66	-4.47	0.37	2.21	100
6	7	50.69	3.02	7	6	-49.70	2.92	0.99	5.95	85

In the Load Flow results of 7-Bus system (Unconstrained case) shown above, Table 4.1 shows the Power Injected, Power Generated, Voltage Phase Angle and Loads for the unconstrained case i.e. when no transmission line limit is applied which is shown in Table 4.2. The Voltage is in per unit value and the Phase angles are in degrees. This table shows the amount of power generated by each generator to satisfy the loads at different buses. It also provides the information about the Voltage and Phase angle at the respective buses for the power generated at each bus. Table 4.2 shows the Line Flow in the transmission lines for the unconstrained case. The line flow is evaluated for both directions to determine the Line losses that are also shown in the same table.

Table 4.3: Power Injected, Voltage and Phase angle for 7-Bus (Constrained case)

CONSTRAINED			POWER INJECTED		POWER GENERATED		LOAD	
BUS No.	VOLTAGE (pu)	ANGLE (Degree)	MW	MVAR	MW	MVAR	MW	MVAR
1	1.05	0.00	184.38	12.01	184.38	12.01	0.00	0.00
2	1.03	-4.13	58.00	-39.58	138.00	-39.58	80.00	0.00
3	1.02	-6.48	-110.00	0.00	0.00	0.00	110.00	0.00
4	1.01	-5.86	60.00	-24.38	100.00	-24.38	40.00	0.00
5	0.98	-11.53	-130.00	0.00	0.00	0.00	130.00	0.00
6	1.04	-5.35	20.00	24.07	220.00	24.07	200.00	0.00
7	0.98	-12.26	-75.00	-18.15	125.00	-18.15	200.00	0.00

Table 4.4: Line Flow and Line Loss for 7-Bus (Constrained case)

CONSTRAINED		LINE FLOW		FROM	TO	LINE FLOW		LINE LOSS		LINE LIMIT
FROM	TO	MW	MVAR			MW	MVAR	MW	MVAR	MW
1	2	132.84	17.55	2	1	-131.21	-7.78	1.63	9.77	135
1	3	51.55	6.59	3	1	-50.57	-0.71	0.98	5.88	58
2	3	24.13	1.14	3	2	-23.96	-0.15	0.17	0.99	55
2	4	18.09	2.97	4	2	-18.00	-2.40	0.10	0.57	45
2	5	112.77	9.89	5	2	-110.35	4.61	2.42	14.49	200
2	6	34.22	-22.47	6	2	-34.06	23.41	0.16	0.95	130
3	4	-35.47	12.35	4	3	35.54	-11.94	0.07	0.41	40
4	5	42.46	1.41	5	4	-41.77	2.76	0.69	4.16	44
7	5	-22.07	-4.45	5	7	22.12	4.76	0.05	0.30	100
6	7	54.06	11.47	7	6	-52.93	-4.69	1.13	6.78	85

In the Load Flow results of 7-Bus system (Constrained case) shown above, Table 4.3 shows the Power Injected, Power Generated, Voltage Phase Angle and Loads for the constrained case i.e. when transmission line limit is applied which is shown in Table 4.4. The Voltage is in per unit value and the Phase angles are in degrees. This table shows the amount of power generated by each generator to satisfy the loads at different buses. It also provides the information about the Voltage and Phase angle at the respective buses for the power generated at each bus. Table 4.4 shows the Line Flow in the transmission lines for the constrained case. The line flow is evaluated for both directions to determine the Line losses that are also shown in the same table.

4.7.2 IEEE 30-BUS TEST SYSTEM

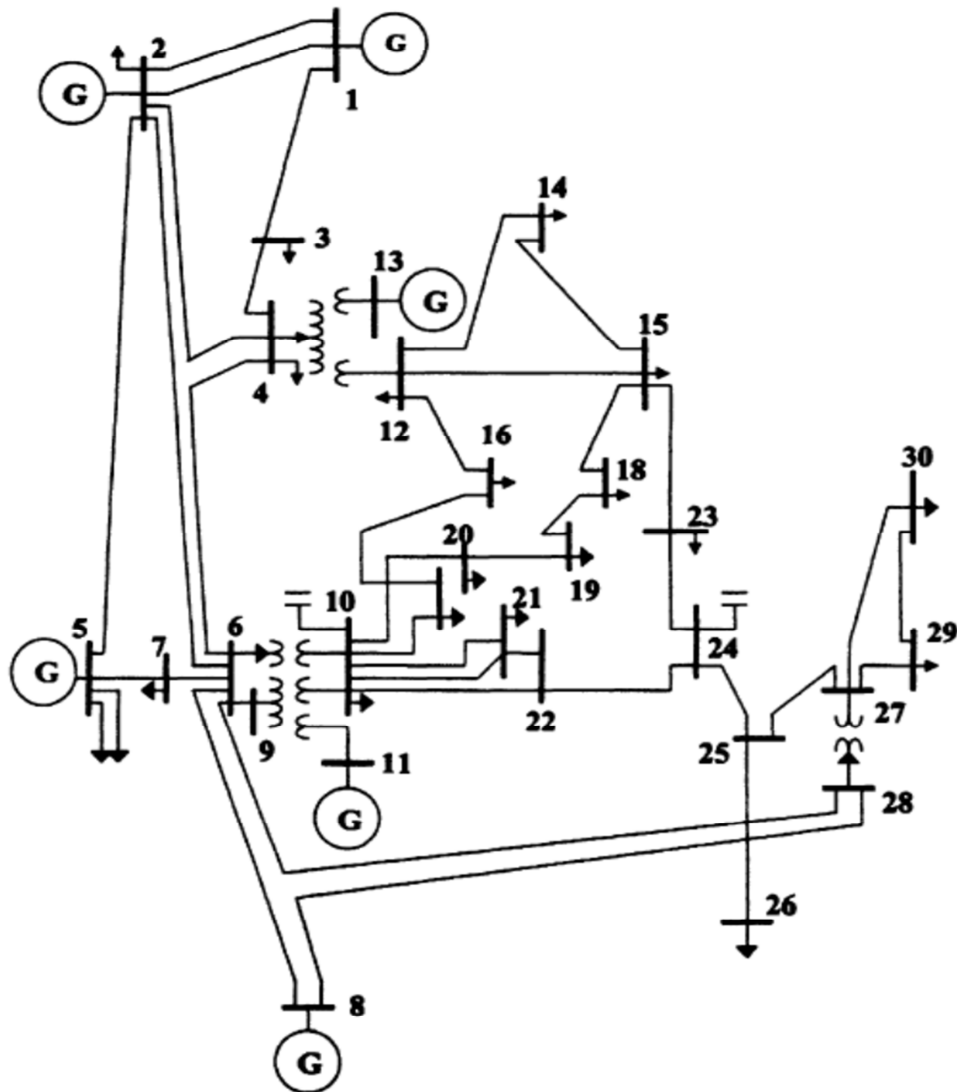


Figure 4.4: One-line Diagram for IEEE 30-Bus Transmission System

Source: (Gnanadass 2015)

The IEEE 30-Bus test system one-line diagram is shown in Figure 4.4. The generator data, bus data and line data used for the IEEE 30-Bus test system is given in Table B.1, Table B.2 and Table B.3 of Appendix-B.

The results obtained after executing a Newton-Raphson Load flow MATLAB Program using IEEE 30-Bus data are shown below:

Table 4.5: Power Injected, Voltage and Phase angle for IEEE 30-Bus
(Unconstrained case)

UNCONSTRAINED			POWER INJECTED		POWER GENERATED		LOAD	
BUS No.	VOLTAGE (pu)	ANGLE (Degree)	MW	MVAR	MW	MVAR	MW	MVAR
1	1.06	0.00	79.72	18.78	79.72	18.78	0	0
2	1.04	-1.18	39.27	-8.26	60.97	4.44	21.7	12.7
3	1.03	-3.16	-2.40	-1.20	0.00	0.00	2.4	1.2
4	1.03	-3.76	-7.60	-1.60	0.00	0.00	7.6	1.6
5	1.01	-3.02	0.00	-20.15	0.00	-1.15	0	19
6	1.02	-4.52	0.00	0.00	0.00	0.00	0	0
7	1.00	-4.45	-22.80	-10.90	0.00	0.00	22.8	10.9
8	1.02	-5.16	-30.00	5.41	0.00	35.41	30	30
9	1.02	-7.34	0.00	0.00	0.00	0.00	0	0
10	0.99	-8.88	-25.80	-2.00	0.00	0.00	25.8	2
11	1.06	-7.34	-0.01	20.38	0.00	20.38	0.01	0
12	1.03	-5.89	-11.20	-7.50	0.00	0.00	11.2	7.5
13	1.06	-3.18	37.00	23.26	37.00	23.26	0	0
14	1.01	-6.67	-6.20	-1.60	0.00	0.00	6.2	1.6
15	1.01	-6.63	-8.20	-2.50	0.00	0.00	8.2	2.5
16	1.00	-8.03	-3.50	-1.80	0.00	0.00	3.5	1.8
17	0.98	-9.89	-40.00	-5.80	0.00	0.00	40	5.8
18	0.99	-8.14	-3.20	-0.90	0.00	0.00	3.2	0.9
19	0.98	-8.85	-9.50	-3.40	0.00	0.00	9.5	3.4
20	0.98	-8.92	-2.20	-0.70	0.00	0.00	2.2	0.7
21	0.99	-8.41	-17.50	-11.20	0.00	0.00	17.5	11.2
22	0.99	-8.10	21.59	0.00	21.59	0.00	0	0
23	1.01	-5.66	16.00	-1.60	19.20	0.00	3.2	1.6
24	0.99	-6.91	-8.70	-6.70	0.00	0.00	8.7	6.7
25	1.01	-5.41	0.00	0.00	0.00	0.00	0	0
26	0.99	-5.84	-3.50	-2.30	0.00	0.00	3.5	2.3
27	1.03	-4.24	26.91	0.00	26.91	0.00	0	0
28	1.02	-4.64	0.00	0.00	0.00	0.00	0	0
29	1.01	-5.44	-2.40	-0.90	0.00	0.00	2.4	0.9
30	1.00	-6.31	-10.60	-1.90	0.00	0.00	10.6	1.9

Table 4.6: Line Flow and Line Loss for IEEE 30-Bus (Unconstrained case)

UNCONSTRAINED		LINE FLOW		FROM	TO	LINE FLOW		LINE LOSS		LINE LIMIT
FROM	TO	MW	MVAR			MW	MVAR	MW	MVAR	MW
1	2	45.25	16.64	2	1	-44.86	-15.45	0.40	1.19	130
1	3	34.47	7.40	3	1	-33.97	-5.35	0.50	2.05	130
2	4	28.00	0.75	4	2	-27.59	0.50	0.41	1.25	65
3	4	31.57	6.78	4	3	-31.44	-6.41	0.13	0.37	130
2	5	20.08	12.85	5	2	-19.83	-11.82	0.25	1.04	130
2	6	36.05	2.76	6	2	-35.36	-0.64	0.70	2.12	65
4	6	36.05	8.49	6	4	-35.90	-7.95	0.15	0.54	90
5	7	19.83	-5.17	7	5	-19.64	5.64	0.19	0.48	70
6	7	3.22	14.83	7	6	-3.16	-14.65	0.06	0.18	130
6	8	25.55	-7.20	8	6	-25.47	7.48	0.08	0.28	32
6	9	25.41	-5.63	9	6	-25.41	6.96	0.00	1.32	65
6	10	14.47	3.00	10	6	-14.47	-1.87	0.00	1.13	32
9	11	0.01	-19.63	11	9	-0.01	20.38	0.00	0.75	65
9	10	25.40	24.20	10	9	-25.40	-22.93	0.00	1.27	65
4	12	15.37	-1.31	12	4	-15.37	1.89	0.00	0.58	65
12	13	-37.00	-20.89	13	12	37.00	23.26	0.00	2.38	65
12	14	6.75	2.45	14	12	-6.69	-2.33	0.06	0.12	32
12	15	13.57	6.26	15	12	-13.43	-5.99	0.14	0.27	32
12	16	20.85	2.79	16	12	-20.46	-1.96	0.39	0.83	32
14	15	0.49	0.73	15	14	-0.49	-0.73	0.00	0.00	16
16	17	16.96	0.16	17	16	-16.73	0.38	0.23	0.54	16
15	18	12.83	1.17	18	15	-12.66	-0.81	0.17	0.35	16
18	19	9.46	-0.09	19	18	-9.40	0.20	0.06	0.12	16
19	20	-0.10	-3.60	20	19	0.10	3.61	0.00	0.01	32
10	20	2.33	4.36	20	10	-2.30	-4.31	0.02	0.05	32
10	17	23.46	6.68	17	10	-23.27	-6.18	0.19	0.50	32
10	21	-5.45	11.69	21	10	5.51	-11.56	0.06	0.12	32
10	22	-6.26	5.91	22	10	6.32	-5.80	0.05	0.11	32
21	22	-23.01	0.36	22	21	23.07	-0.24	0.06	0.12	32
15	23	-7.11	3.05	23	15	7.17	-2.93	0.06	0.12	16
22	24	-7.80	6.04	24	22	7.91	-5.86	0.11	0.17	16
23	24	8.83	1.33	24	23	-8.73	-1.12	0.10	0.21	16
24	25	-7.88	0.29	25	24	8.00	-0.08	0.12	0.20	16
25	26	3.54	2.37	26	25	-3.50	-2.30	0.04	0.07	16
25	27	-11.54	-2.29	27	25	11.69	2.57	0.15	0.28	16
28	27	-1.95	-2.97	27	28	1.95	3.02	0.00	0.05	65
27	29	6.19	1.66	29	27	-6.10	-1.50	0.08	0.16	16
27	30	7.09	1.66	30	27	-6.93	-1.36	0.16	0.30	16
29	30	3.70	0.60	30	29	-3.67	-0.54	0.03	0.06	16
8	28	-4.53	0.62	28	8	4.54	-0.58	0.01	0.04	32
6	28	2.60	-3.56	28	6	-2.60	3.57	0.00	0.01	32

In the Load Flow results of IEEE 30-Bus (Unconstrained case) shown above, Table 4.5 shows the Power Injected, Power Generated, Voltage Phase Angle and Loads for the unconstrained case i.e. when no transmission limit is applied, where the transmission line limit is shown in Table 4.6. The Voltage is in per unit value and the Phase angles are in degrees. This table shows the amount of power generated by each generator to satisfy the loads at different buses. It also provides the information about the Voltage and Phase angle at the respective buses for the power generated at each bus. Table 4.6 shows the Line Flow in the transmission lines for the unconstrained case. The line flow is evaluated for both directions to determine the Line losses that are also shown in the same table.

The Load Flow results of IEEE 30-Bus (Constrained case) are provided in the CD enclosed in Appendix E. The results obtained for constrained case are of the same length as the above shown case. In the Constrained case transmission line limits are taken into consideration which are provided in the CD enclosed in Appendix E, and the results of Load Flow are obtained after re-dispatching the generators.

4.7.3 INDIAN UTILITY 146-BUS SYSTEM

The Indian Utility 146-Bus System one-line diagram is shown in Figure 4.5. The generator data, bus data and line data used for the Indian Utility 146-Bus System is given in Table C.1, Table C.2 and Table C.3 of Appendix-C.

The results obtained after executing a Newton-Raphson Load flow MATLAB Program using the Indian Utility 146-Bus System data is shown in Appendix-C.

In the Load Flow results of Indian Utility 146-Bus System (Unconstrained case) shown in Appendix-C, Table C.4 shows the Power Injected, Power Generated, Voltage Phase Angle and Loads for the unconstrained case i.e. when no transmission

line limit is applied, where the transmission line limit is shown in Table C.5 of Appendix-C. The Voltage is in per unit value and the Phase angles are in degrees. This table shows the amount of power generated by each generator to satisfy the loads at different buses.

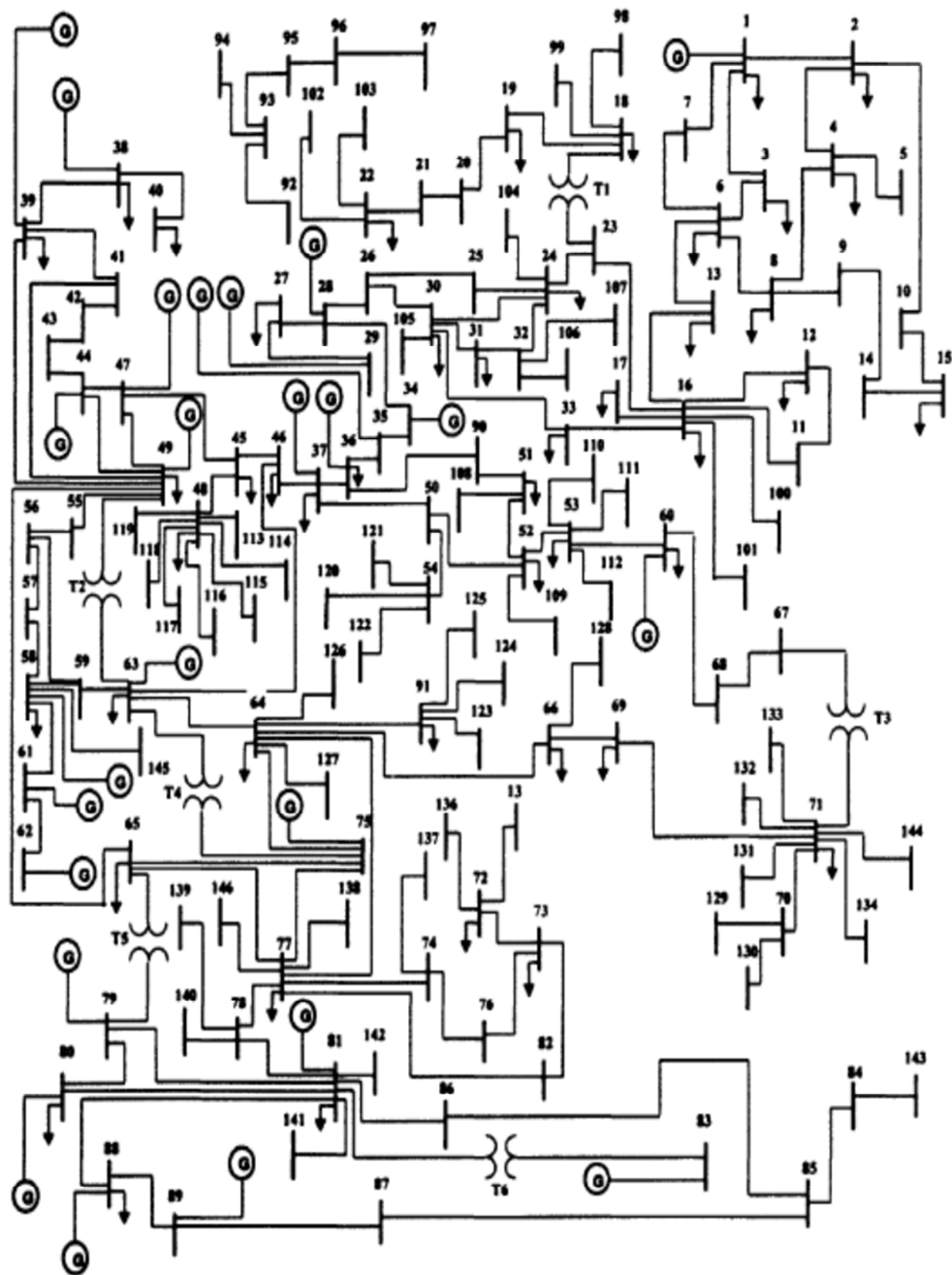


Figure 4.5: One-line Diagram for Indian Utility 146-Bus Transmission System

Source: (TamilnaduElectricityBoard 2015)

It also provides the information about the Voltage and Phase angle at the respective buses for the power generated at each bus. Table C.5 in Appendix-C, shows the Line Flow in the transmission lines for the unconstrained case. The line flow is evaluated for both directions from which the Line losses are determined that are also shown in the same table.

The Load Flow results of the Indian Utility 146-Bus (Constrained case) is provided in Appendix-E (CD enclosed). The results obtained for constrained case are of same length as the above shown case. In the Constrained case transmission line limits are taken into consideration, where the transmission line limits are provided in Appendix-E (CD enclosed) and the results of Load Flow are obtained after re-dispatching the generators.

4.8 SUMMARY

The main objective of undertaking a Load Flow analysis is to provide detailed information on the state of the power system, that is; power injected at every bus from the generators, the voltage and phase angle at all the buses and also the line flow and losses in the transmission lines. This information provides the data for the further analysis evaluation utilised in the DMF for ROTC including congestion, transmission pricing and Reliability analysis. It also helps the operator to smoothly operate the system and receive indication if there is any disturbance in the Power system network. Finally as stated in the previous sections we have presented summary results and relevant analysis in the sections with the detailed results and the codes of the studies and simulations conducted in the relevant Appendices due to their large volume.

CHAPTER - 5

TRANSMISSION COSTING

5.1 INTRODUCTION

In a deregulated power system market it becomes necessary to have a suitable transmission pricing method in order to guarantee an acceptable level of security and reliability. Till now it's a major issue to exactly evaluate and assign the optimal transmission cost considering known Pricing methods (Murali, Kumari et al. 2011). The transmission pricing is the process which helps the transmission service provider to optimally recover the cost of supplying the electricity to the customers.(Kharbas, Fozdar et al. 2011)

The main aim of the transmission pricing scheme is to recover all types of cost (embedded as well as incremental) incurred throughout the transmission system. The key challenge encountered by the electric power industry is to allocate the price for the transmission services in an open access system. According to FERC (Federal Energy Regulatory Commission) transmission system will remain monopolistic but they have to still continue to provide the basic services and ancillary service maintenance for the transactions. The basic transmission system cost consists of a fixed cost for the capacity used or embedded system cost. Generally the transmission service provider charges a fixed cost for the transmission service from the customers based on Postage stamp method or contract path method. (Pan, Teklu et al. 2000)

Spot pricing was adopted by Chile, US and New Zealand whereas Europe adopted some simpler pricing method in their system. The optimal pricing of electricity at every location in the network is the marginal cost of supplying it at each node. The main concern after electricity generation is to supply the power at each node

considering losses and limitations of transmission. Sometimes transmitting power to longer distances costs relatively more than installing a local generating station in the long run as the losses are too high in the long distance transmission and that gets reflected on the price of the power provided at that point. In transmission pricing, one of the key economic elements is to perceive and conceptualize an appropriate cost for the optional approach. The consumer should buy at the commodity price rather than the production cost and the supplier should generate the power at less than the market price. So, if the price is more than the marginal cost, the power consumption will be less and if the price is less than the marginal cost, the consumption will be more. Therefore pricing should be undertaken judiciously and optimally. The transmission pricing can be carried out optimally by relating it with the maximisation of net welfare taken from the consumption of electrical power. (Green 2004)

The simplified Lagrangean function for maximisation is:

$\max(dg) =$

$$\sum_k B(d_k) - \sum_j C(g_j) - \mu_e \left(\sum_k (d_k) + l - \sum_j (g_j) \right) - \mu_i^{QS} (|z_i| - z_i^{max}) \quad (5.1)$$

MW-Mile Method
Bialek's Method

(Green 2004)

Where,

B: Benefits from consuming electricity

C: Cost of generation

d_k : demand at node k

g_j : generation at node j

z_i : flow at line i

l : transmission losses

z_i^{max} : maximum flow limit at line i

μ_e : Lagrangean multiplier on the energy balance constraint

μ_i^{QS} : Lagrangean multiplier on flow constraint

The price at node k can be given by:

$$P_k = \mu_e \left[1 + \frac{\partial l}{\partial d_k} \right] + \sum_i \mu_i^{QS} \frac{\partial z_i}{\partial d_k} \quad (5.2)$$

Roughly the average loss in the transmission line is about 5% of the electrical power supplied. As we know the power loss is proportional to the square of the line flow, so the marginal cost will become 10% of the power supplied.

5.2 NATURAL MONOPOLISTIC PRICING

The measure of the natural monopolies is the Minimum Efficient Scale (MES). For perfectly competitive markets, the price is equal to the Marginal Cost. The following diagram in Figure 5.1, of cost curves shows the Marginal Cost curve intersecting the Average Cost curve at its minimum cost. To cover the cost, monopolistic firm can choose point (y_{AC}, p_{AC}) , but in such a situation the production will not be sufficient to handle the the market demand. In the case of government Monopoly, if point (y_{MC}, p_{MC}) is chosen, the market will have sufficient production supply but will encounter negative recovery costs. However these can be compensated by subsidies for certain sectors such as Agriculture.(Krause 2003)

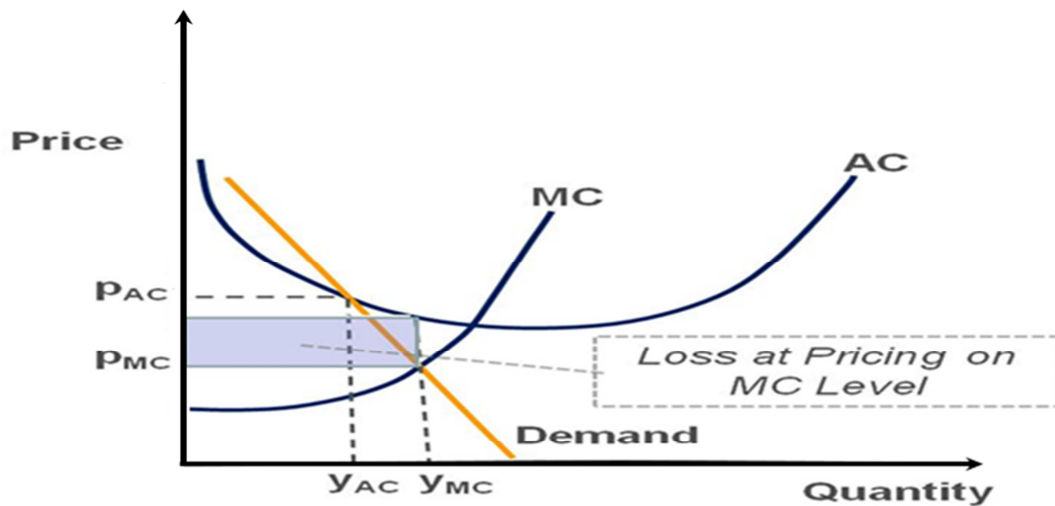


Figure 5.1: Cost curve showing Natural Monopoly situation

Source: (Krause 2003)

5.3 'EFFICIENT PRICING METHOD IS A NECESSITY'. WHY?

An efficient and optimal pricing method is imperative to ensure the transmission and availability of electrical power to consumers at a reasonable price and to economically dispatch the existing generating capacity for the same.

If the power transmission is charged below its marginal cost then the power import to farther locations will be profitable and the customers staying nearby will enjoy a much lower cost, but if the pricing of transmission services is above marginal cost then the electricity market will shrink, as the power import will become costly with the reduction of market competition.

The transmission pricing methodology has to transparently show the actual cost of transmission which includes all the constraints so that private party investors will be able to clearly estimate all the constraints that are involved correctly for the expansion of transmission capacity and for installation of new generation capacity. (Nayar, Sinha et al. 2001)

5.4 CONDITIONS FOR OPTIMAL TRANSMISSION PRICING TECHNIQUE

The Optimal Transmission Pricing technique should be simple to implement, inspire investment and flexible in nature so as to recover the overall cost with profits. It should abide by the Electrical regulations of the country and also be compatible with the future modifications in the transmission system. It should not put any hindrance in the levels of security and should behave normally with any systematic change. It should inspire fairness and political suitability.

5.5 ELEMENTS OF TRANSMISSION COST

5.5.1 OPERATING COST

It is the fuel/power generation cost for which the transmission companies are liable to provide services. Operating cost is a combination of the cost of rescheduling and re-dispatching the generators which usually happens due to variation in losses, power flow and bus voltage limits. Apparently these Ancillary services are also added to this cost. The additional components can be spinning reserves requirement and the start-up cost which affects the cost in generators rescheduling. It can be estimated hourly using power flow algorithms that include all the transmission, generation and reliability constraints.

5.5.2 OPPORTUNITY COST

Opportunity cost is one of the components of reliability cost (Lai 2002). In past transactions this cost was not taken into consideration while designing transmission pricing. This cost is considered as the profit/advantage that the transmission

companies receive due to limitations in transmission for a particular transaction. The added cost happens because for some transactions it is not possible to utilize low cost generation which can possibly incur congestion in the transmission line. It can also be the revenue generated due to transactions that could not be met because of operating limitations. This is a somewhat baffling cost component which is there in transmission pricing.

5.5.3 REINFORCEMENT COST

This cost comprises of all the costs required for setting up all the necessary services by the transmission company for the particular agreed transmission. It can also be a cost of new installation which is temporarily made inactive for a particular transaction. It is not so easy to estimate and identify the components which induce the reinforcement and hence it is not easy to estimate reinforcement costs.

5.5.4 EMBEDDED COST

This is the biggest element of the total transmission cost of any transaction. It comprises of the overall assets and the preceding costs involved in maintenance and supplying continuous electrical power. It is named Embedded as this cost cannot be disassociated from the current cost of generating electricity. The commonly charged embedded cost is the capital involved in transmission facilities such as Transmission lines, Power transformers, etc (Energy Dictionary). It also includes the cost of salaries of staff involved in administration, billing and accounting and the cost of providing the reactive power support.(Murali, Kumari et al. 2014)

5.6 TRANSMISSION PRICING METHODS

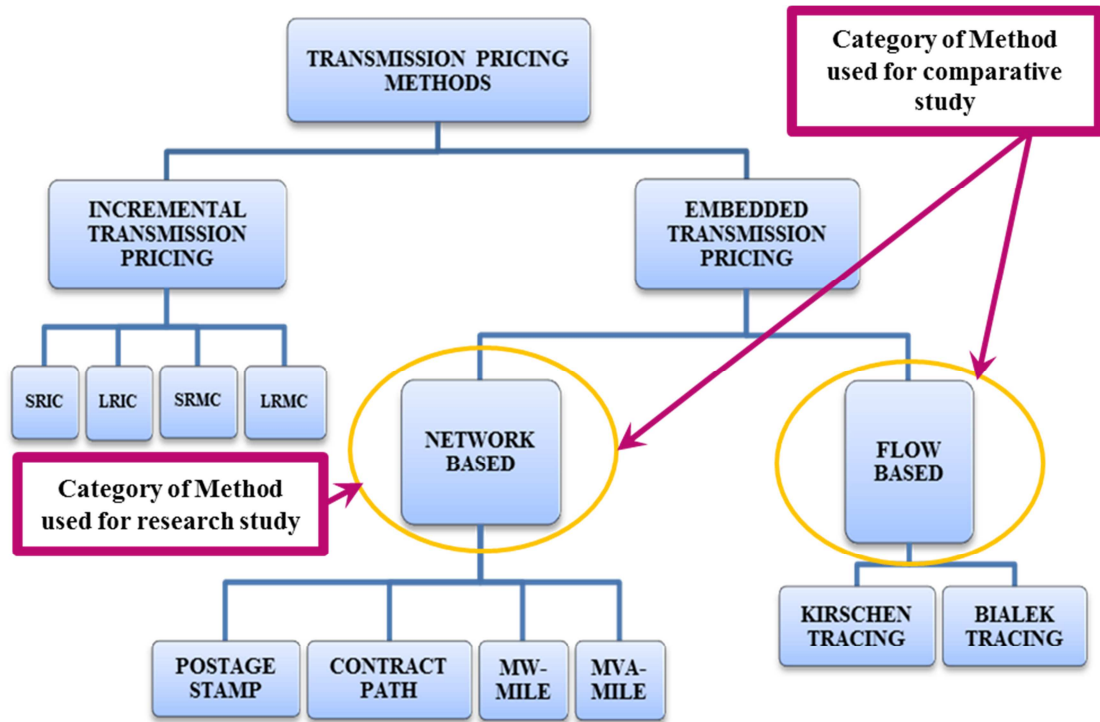


Figure 5.2: Flow chart for Transmission pricing methods

Flow chart shown in Figure 5.2 describes the transmission pricing methods according to its types and the methods used for research and comparative purpose in the research. All the methods are described below in brief.

5.6.1 INCREMENTAL BASED TRANSMISSION PRICING METHODS

5.6.1.1 Short-Run Incremental Cost Pricing (SRIC)

In this pricing method the cost of providing any increased supply for any transaction is involved and can be evaluated from the power flow algorithms considering all the limiting values and conditions.

5.6.1.2 Long-Run Incremental Cost Pricing (LRIC)

In this pricing method the reinforcement cost and the cost of operation which are known to be the long run cost are included in the transmission pricing methodology for a given transaction.

5.6.1.3 Short-Run Marginal Cost Pricing (SRMC)

This is the cost involved in transferring an extra 1 MW of electrical power for a particular transaction. It can be evaluated using power flow. And the price of transaction is estimated by taking the difference between the marginal cost of the operation of the source bus and the sink bus and then it is multiplied by the modulus of SRMC to get the price on the basis of SRMC. The value of SRMC determined can be negative.

SRMC is advantageous in a way as it provides nearly accurate price indications for the economic operation and location of generators and load.

However, the disadvantage of SRMC is that it only estimates the cost of operation. In the presence of any limitation it gives inaccurate results and discourages future transmission expansion, thus making itself rigid.

$$SRMC_{tr} = \sum_{i \in B_{tr}} BMC_i * P_{i,tr} \quad (5.3)$$

Where, BMC_i , is the marginal cost at bus 'i'

$P_{i,tr}$, is the power introduced in bus 'i' for transaction 'tr'

B , the transmission busses involved during the transaction

5.6.1.4 Long-Run Marginal Cost Pricing (LRMC)

This gives the current price for planning necessary future investment, needed to withstand the increment in the marginal future demands at various positions in the transmission system considering the demand and supply growth for peak intervals. Marginal operating and reinforcement cost are utilised to evaluate the transmission price for a particular transaction. In determining the incremental transmission prices the Locational Marginal Pricing is the most likely method incorporated by many countries.(Murali, Kumari et al. 2014)

$$\text{Marginal price} = \frac{\partial f_c}{\partial p} \quad (5.4)$$

and Incremental Price = ∂f_c

Where, f_c is the fuel charges and P is the power generated.

5.6.2 EMBEDDED TRANSMISSION PRICING

5.6.2.1 Network Based Transmission Pricing Methods

These methods do not correspond to the operational conditions of the system and it only considers the structural arrangement of the transmission system.

5.6.2.1.1 Postage Stamp Method

Postage Stamp Method (Postage Stamp Rate Method/ Rolled-In Embedded Method) is the method used by the transmission service providers in order to charge the fixed cost from the consumers.

“This is the approach adopted by Sir Rowland Hill when the Post Office was reformed in 1840 – a user could send a letter anywhere in the country for the standard fee of one penny.”(Bell, Green et al. 2011)

This method does not consider any load flow estimations and does not require the distance of power flow either. Under this method the customers are charged depending on average embedded cost and the amount of power transmitted i.e. by adding together, all the transmission charges and dividing it by the peak system demand and hence generates a flat rate for each MW consumed. (Lai 2002)

$$R_T = TC * (P_t / P_{\text{peak}}) \quad (5.5)$$

Where,

R_T : Price of transmission for transaction ‘T’

TC: Transmission Charges

P_t : Transaction ‘T’ load at peak load time in MW

P_{peak} : Peak load in MW

The main disadvantage of this method is that it does not differentiate the near or far distant consumers and presents an inaccurate charging process.

5.6.2.1.2 Contract Path Method

Under this method the users are charged according to the artificially chosen path in the transmission system using postage stamp method which is calculated separately for every specific path (Krause 2003). This method also doesn’t consider the system operation factor and moreover the load flow for any estimation is not carried out.

5.6.2.1.3 MW Mile Method: (Line-by Line Method)

This method is considered as the first method which can recover the fixed transmission cost based on the actual use of transmission capacity. The mode of calculation is based upon the amount, route and travelled distance of the power transmitted.(Kharbas, Fozdar et al. 2011) This method comes under embedded cost allocation techniques and can be applied in three ways, namely Absolute, Reverse and Dominant. The general expression for MW mile method is:

$$C_k = \sum_{i=1}^N \frac{L_i * F_i * P_i^k}{\bar{P}_i} \quad (5.6)$$

Where, C_k : Cost of transmission for each user ‘k’,

L_i : Length of line i,

F_i : Predetermined unit cost reflecting the cost per km of circuit i,

in Rs.(million) / Km,

P_i : Power limit of line i,

P_{ik} : Power flow on the circuit i , due to user k ,

N : Numbers of transactions,

i : Total number of lines.

The merit of using this method is that it gives nearly accurate transmission cost of the operating system used. And the demerit is that it does not recover the full embedded cost as it charges for the base case system and overlooks the system reserves.

5.6.2.1.3.1 Absolute MW Mile Method

In this method the direction of power flow is not considered in the transmission network for calculating the prices of transmission. The power flow due to customer 'k' on the line 'i' is considered with a condition,

$$P_{ik} = |P_{ik}| \text{ for direct and reverse power flows.} \quad (5.7)$$

5.6.2.1.3.2 Reverse MW Mile Method

In this method the reverse direction power flow is also considered in pricing and the price is based upon the total flow. It is noted that the power flow in the reverse direction lowers the load on the transmission line and hence lowers the chances of congestion in the system. The power flow due to customer 'k' on the line 'i' is considered with a condition,

$$P_{ik} = \text{Positive (+) for direct power flows,} \quad (5.8)$$

$$\& P_{ik} = \text{Negative (-) for reverse power flows.} \quad (5.9)$$

5.6.2.1.3.3 Dominant MW Mile Method

This method is a combination of absolute and reverse MW mile method. In this method the pricing for customers is performed using direct power flow caused in the transmission line by the customers, without considering the reverse line flow and

hence, the customers are not charged for any reverse power flows. In this method the power flow due to customer 'k' on the line 'i' is considered with a condition,

$$P_{ik} = |P_{ik}| \text{ for direct power flows} \quad (5.10)$$

$$\text{Or } P_{ik} = 0 \text{ for reverse power flows} \quad (5.11)$$

5.6.2.1.4 MVA Mile Method

The transmission service used can be best measured by considering both active and reactive power. This method includes the pricing of reactive power along with the MW Mile method results. This method charges for any transaction based on the magnitude of power transaction and also the distance over which power is transmitted. This method considers AC power flow for its estimations.

5.6.2.2 Flow Based Transmission Pricing Methods

5.6.2.2.1 Bialek Tracing Method

In this method it is assumed that the lines are loss less i.e. the power flow from the sending end to the receiving end is same. The easy process to have a lossless power flow is by considering an average power flow between two ends of the line and by adding half of the loss to each side of the power injected. The flow in the transmission line due to generators and loads are determined using upstream and downstream algorithms.

➤ Upstream algorithm: Under this the total power flowing towards the node is considered and expressed as,

$$P_i^g = \sum_{j \in \alpha_i^{(u)}} |P_{ij}^g| + P_{Gi} \quad (5.12)$$

Where,

$$i = 1, 2, 3 \dots n$$

$\alpha_i^{(u)}$, Set of nodes directly supplying power to nodes

P_i^g , total unknown Power Flow through line 'i'

$|P_{ij}^g|$, total/gross unknown Power Flow from node j to i

P_{Gi} , power generation at node i

As, $|P_{ij}^g| = |P_{ji}^g|$ considering loss less lines,

$|P_{ij}^g|$ can be written as $\left(\frac{P_{ji}^g}{P_j^g} \right) * P_j^g$, as the transmission losses are small

then $\frac{P_{ji}^g}{P_j^g} \approx \frac{P_{ji}}{P_j}$ where, P_{ji} is the value of Power Flow from node j in

line ji and P_j is the actual flow at node j. This means that the total flow distributed at the node is similar to the actual Power Flow through that node, and the equation is rearranged as,

$$P_i - \sum_{j \in \alpha_i^{(u)}} \frac{|P_{ji}|}{P_j} * P_j^g = P_{Gi} \quad (5.13)$$

$$\text{Or, } A_u P_{gross} = P_G \quad (5.14)$$

Where, A_u is the upstream distribution matrix, P_{gross} is the vector for unknown gross nodal Power Flow and P_G is the vector for nodal generation.

$$[A_u]_{ij} = \begin{cases} 1 & \text{for } i = j \\ -\frac{|P_{ji}|}{P_j} & \text{for } j \in \alpha_i^{(u)} \\ 0 & \text{otherwise} \end{cases} \quad (5.15)$$

Or, $P_{gross} = A_u^{-1} P_G$ and its 'i'th elements is,

$$P_i^g = \sum_{k=1}^n [A_u^{-1}] P_{Gk} \text{ for } i=1, 2 \dots n \quad (5.16)$$

The final equation for outflow in line 'ij' from 'ith' node after using proportional

$$\text{sharing principle is } P_i^g = \frac{P_{ji}^g}{P_j^g} * P_j^g = \frac{P_{ji}^g}{P_j^g} \sum_{k=1}^n [A_u^{-1}] P_{Gk}$$

$$P_i^g = \sum_{k=1}^n D_{ij,k}^g P_{Gk} \text{ for } j \in \alpha_i^d \quad (5.17)$$

Where, α_i^d is the set of nodes supplied from node i. and $D_{ij,k}^g = \frac{P_{ji}^g}{P_j^g} [A_u^{-1}]$ is

the topological distribution factor that signifies the part of generation from kth generator into line ij. This factor gives the proportion of the generation from the particular generator for power flow and it is always positive.

➤ Downstream algorithm:

This algorithm is very much similar to the upstream algorithm and the main difference is that it gives each load contribution for the power flow in the transmission line here P_i^l is the addition of all outward flow between load and node i.

5.6.2.2.2 Kirschen Tracing Method

This method considers the set of load flow equations which arranges the network branches and buses into different collective units. It considers that the contribution of generator and load for the transmission line flows can be evaluated using the proportionality principle. This method can be used for the estimation of both active and reactive power flows, also for the contribution of the generators.

Some concepts for this method are:-

Generator domain: the set of buses where power reaches from the generator.

Common: the set of all the buses which receives power from the same generator source.

Links: the lines that are connecting two different commons.

The graph is formed by combining buses into commons and branches into links (Strbac, Kirschen et al. 1998). The inflow and outflow of all commons are then evaluated, where inflow is the summation of generator power and the power from linked commons to this common, and the outflow is the power transferred from this common to other commons via links.

The recursive method is expressed as,

$$F_{ik} = C_{ij} * F_{jk} \quad (5.18)$$

$$I_k = \sum_j F_{jk} \quad (5.19)$$

$$C_{ik} = \frac{\sum_k F_{ik}}{I_k} \quad (5.20)$$

Where, F_{ik} is the flow in common 'k' due to generator 'i', C_{ij} is the generator 'i' contribution for load and common 'j' outflow, F_{jk} is the flow in the link due to common 'j' and 'k', I_k is the inflow in common 'k', C_{ik} is the generator 'i' contribution for load and common 'k' outflow, F_{ik} is the flow in the link between common 'i' and 'k' due to generator 'i'.

Contribution of Load: The load contribution for the flow in branch can be calculated using the same approach considering the followings:-

Load domain: the set of buses involved in transferring power to load.

Common: the set of buses which transfers power flow to the same load.

Link: the branches connecting two different commons.

The graph is formed by combining buses into commons and branches into links and the contribution of load is estimated by considering the power flow leaving the

commons and then for whole graph considering outflows of power. Here the contribution is dependent on the conditions of operation.

5.7 FLOW CHART FOR TRANSMISSION COSTING

The following Flow Chart in Figure 5.3 explains the process and methodological framework for the analysis and verification of the proposed application of PTDF method to determine transmission costing and its comparison with other methods.

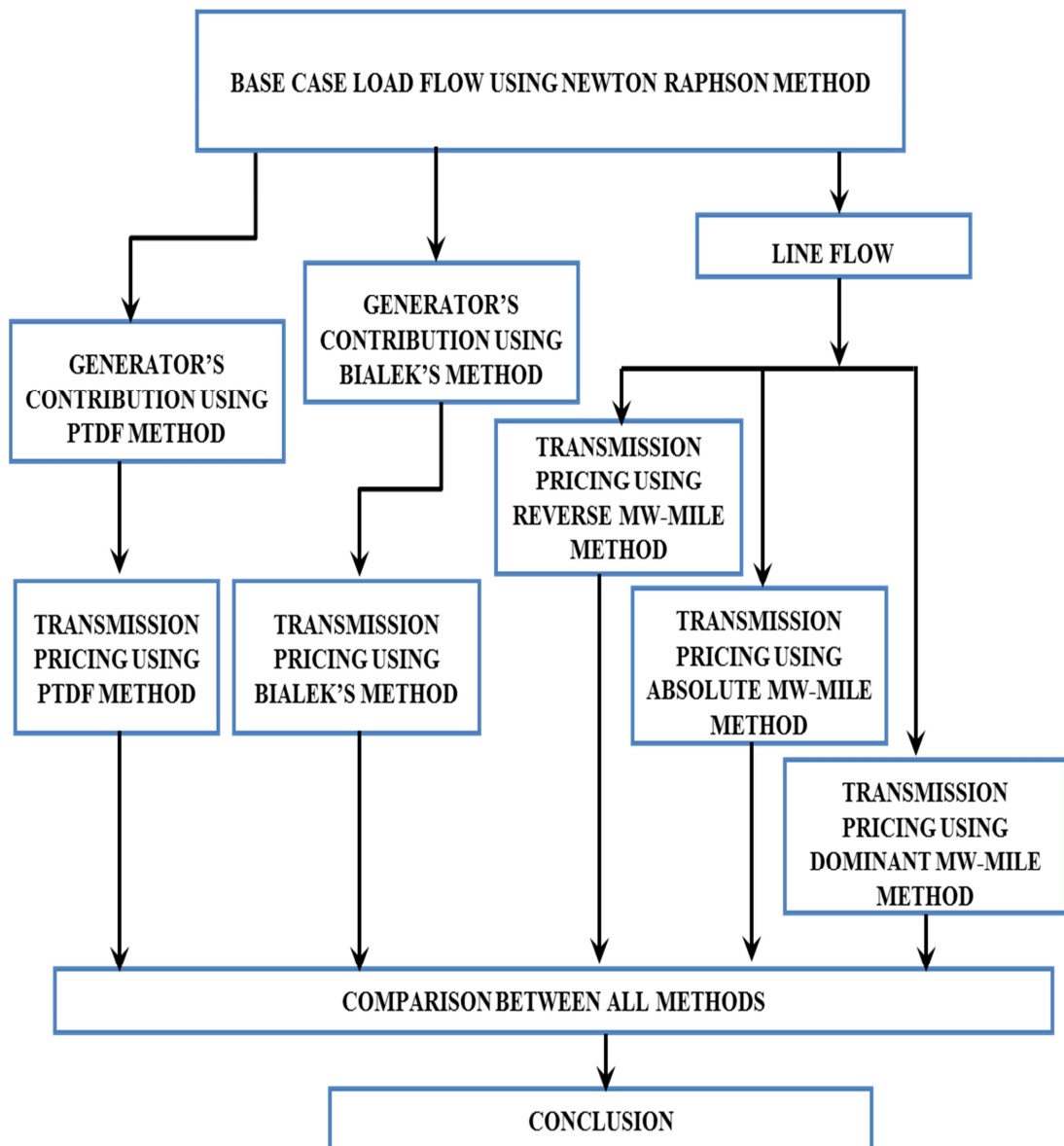


Figure 5.3: Flow chart showing Transmission Costing calculation process.

5.8 RESULTS AND ANALYSIS

The following results of transmission costing for the 7-Bus case study is given below to verify the output of our proposed application of PTDF method with the published results in literature. These results were used as a part of the procedure to calculate ROTC.

5.8.1 7- BUS SYSTEM

The total transmission Costing using proposed application of PTDF method, Bialek's method, Reverse MW-Mile method, Absolute MW-Mile method and Dominant MW-Mile method are shown as bar charts in Figures 5.4, 5.5, 5.6, 5.7 and 5.8 and the Total Transmission Cost comparison between all the methods used are shown in Figure 5.9.

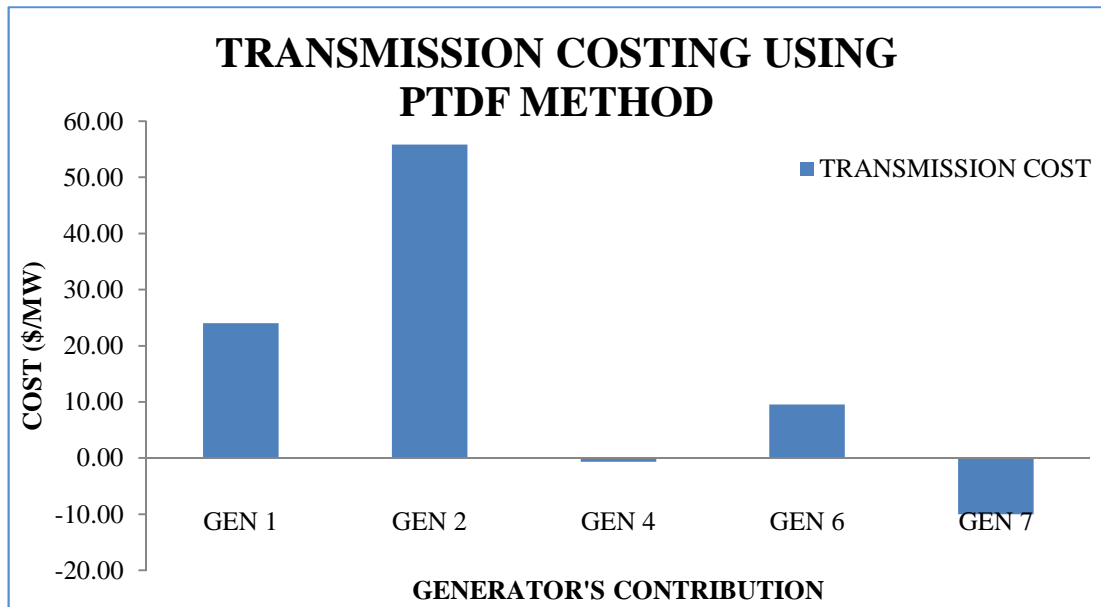


Figure 5.4: Bar Chart showing Transmission Costing using application of PTDF Method for 7-Bus System

Using the generator's contribution obtained from proposed application of PTDF method and Bialek's method in Chapter 6, Transmission Costing is evaluated considering the Transmission line cost.

The obtained results for total transmission cost using proposed application of PTDF method is 78.73 (\$/MW), which is slightly more than the cost obtained using Bialek's method which is 59.23 (\$/MW). But by comparing the transmission cost using proposed application of PTDF method with Absolute MW Mile method, the former provides the most similar results i.e. 71.34 (\$/MW). This comparison shows that proposed application of PTDF method is a justified method which can be used for estimating the transmission cost of the transmission system. After analysing the cost obtained from all of the results it can be seen that the cost obtained from the proposed application of PTDF method is more than all the mentioned methods, so this method also justifies for obtaining the sufficient revenues for the transmission system operators for present maintenance and future development.

Since the results for all the methods are comprehensive they are provided in table format in Appendix. E (CD enclosed).

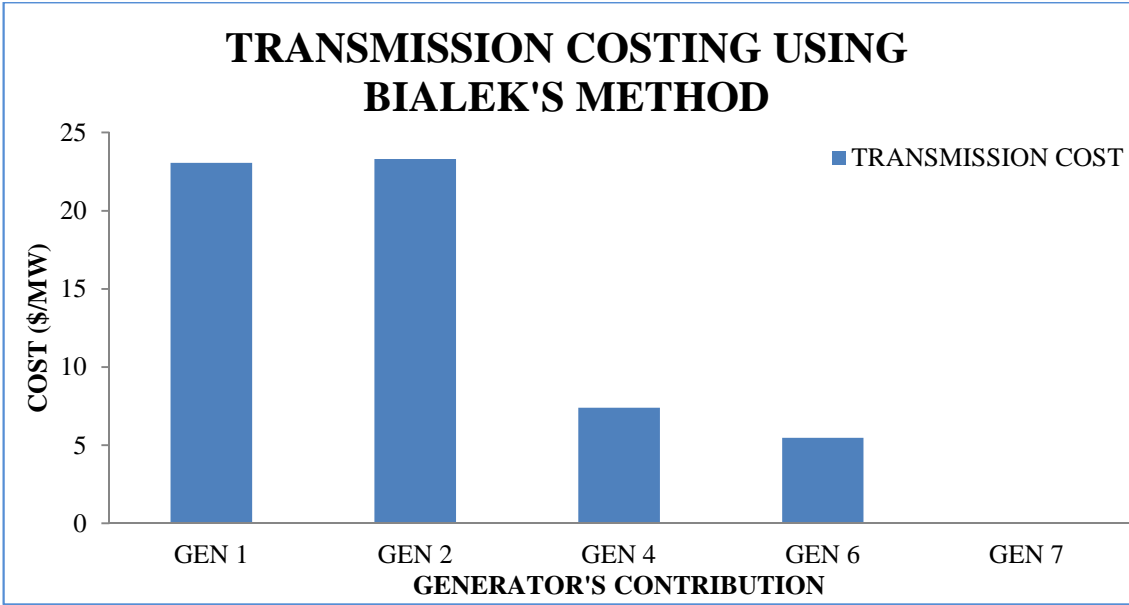


Figure 5.5: Bar Chart showing Transmission Costing using BIALEK'S Method for 7-Bus System

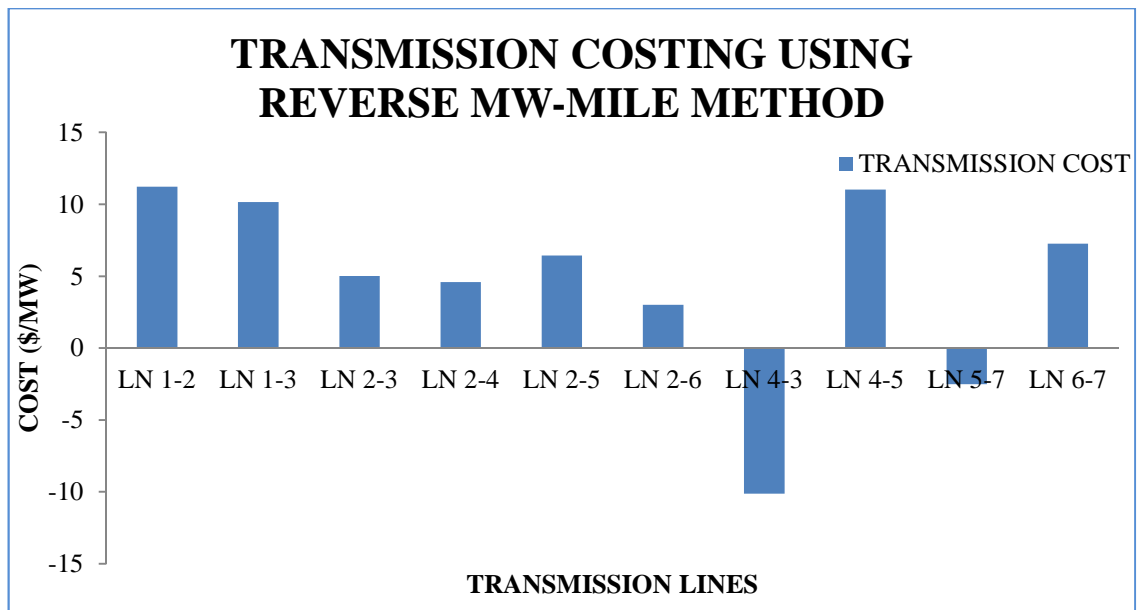


Figure 5.6: Bar Chart showing Transmission Costing using Reverse MW- Mile Method for 7-Bus System

The negative transmission cost for some generators and transmission line is due to power flow in opposite direction of the actual power flow.

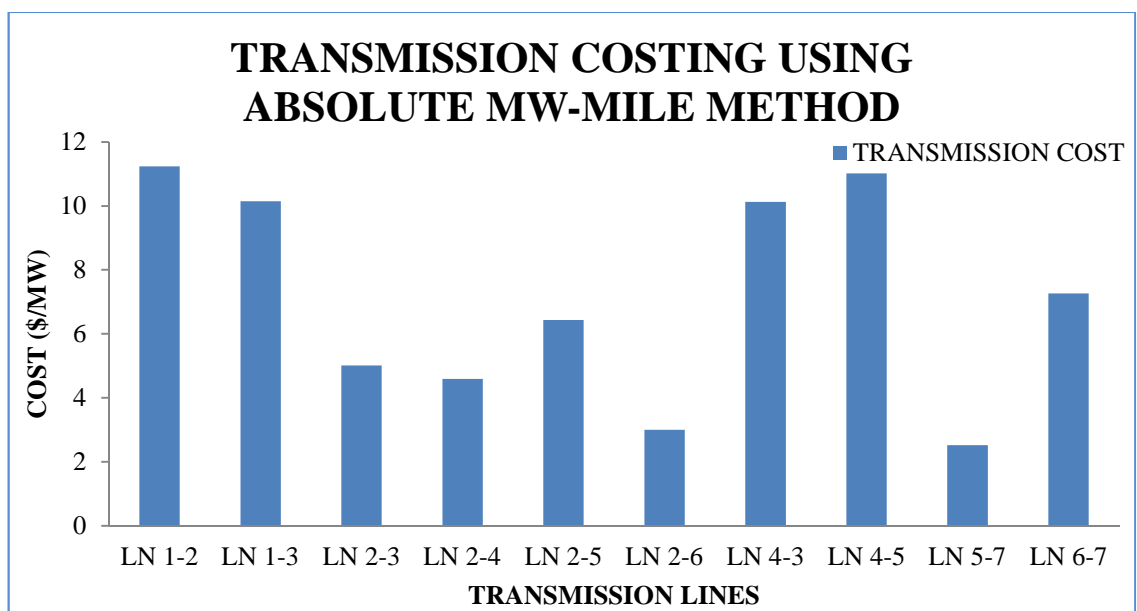


Figure 5.7: Bar Chart showing Transmission Costing using Absolute MW- Mile Method for 7-Bus System

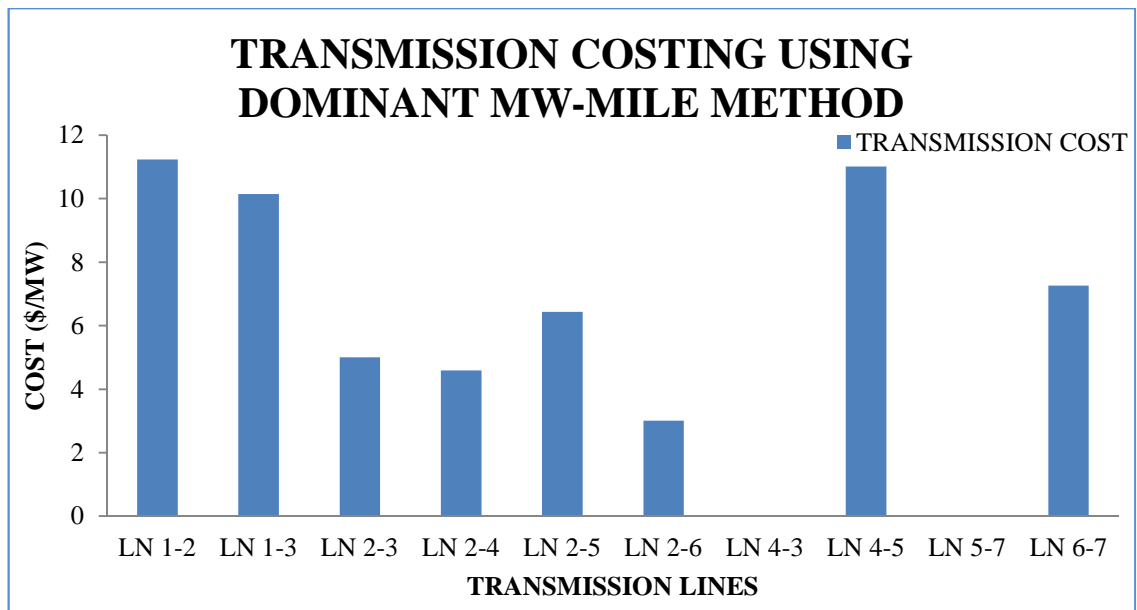


Figure 5.8: Bar Chart showing Transmission Costing using Dominant MW- Mile Method for 7-Bus System

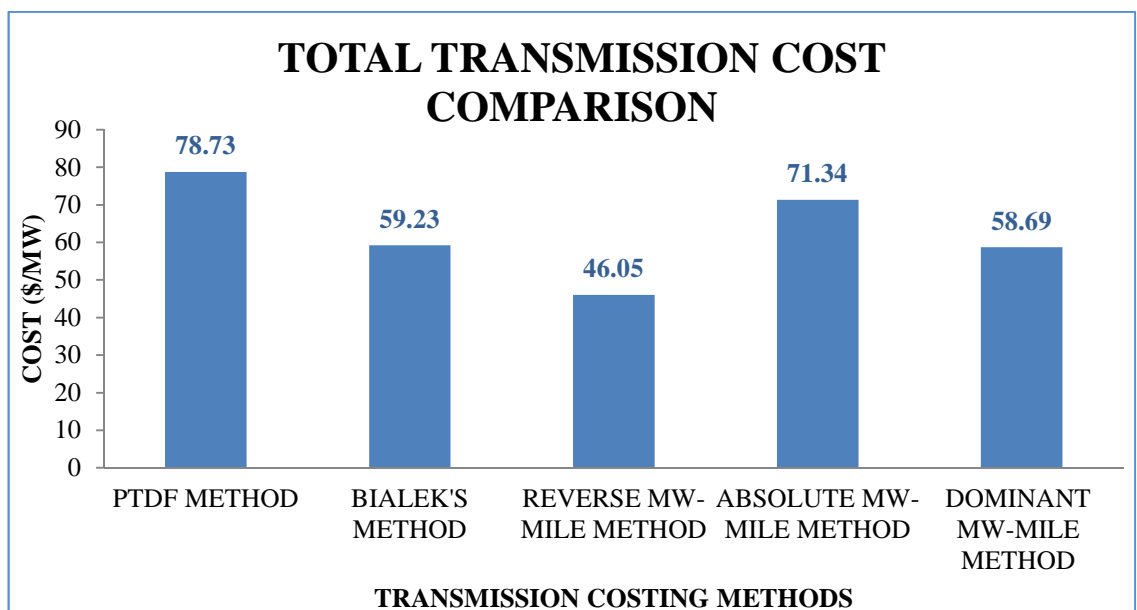


Figure 5.9: Bar Chart showing Total Transmission Cost Comparison for 7-Bus System

5.8.2 IEEE 30- BUS SYSTEM

The total transmission Costing using application of PTDF method, Bialek's method, Reverse MW-Mile method, Absolute MW-Mile method and Dominant MW-Mile method are shown as a bar chart in Figure 5.10, 5.11, 5.12, 5.13 and 5.14, the Total Transmission Cost comparison between all the methods used is shown in Figure 5.15.

Using the generator's contribution obtained from the proposed application of PTDF method and Bialek's method in Chapter 6, transmission Costing is evaluated considering the Transmission line cost.

The obtained results for total transmission cost using proposed application of PTDF method is 178.26 (\$/MW), which is to the same as the cost obtained using Bialek's method. Also by comparing the transmission cost using the proposed application of PTDF method with Absolute MW Mile method it gives a similar results i.e. 170.69 (\$/MW). This comparison shows that proposed application of PTDF method is justified and can be used for estimating the transmission cost of the transmission system.

After analysing the cost obtained from all of the results it can be seen that the cost obtained from the proposed application of PTDF method is more than all the mentioned methods, so this method is also justified by obtaining the sufficient revenues for the transmission system operators for maintenance as well as for future development.

Since the results for all the methods are comprehensive they are provided in table format in Appendix. E (CD enclosed).

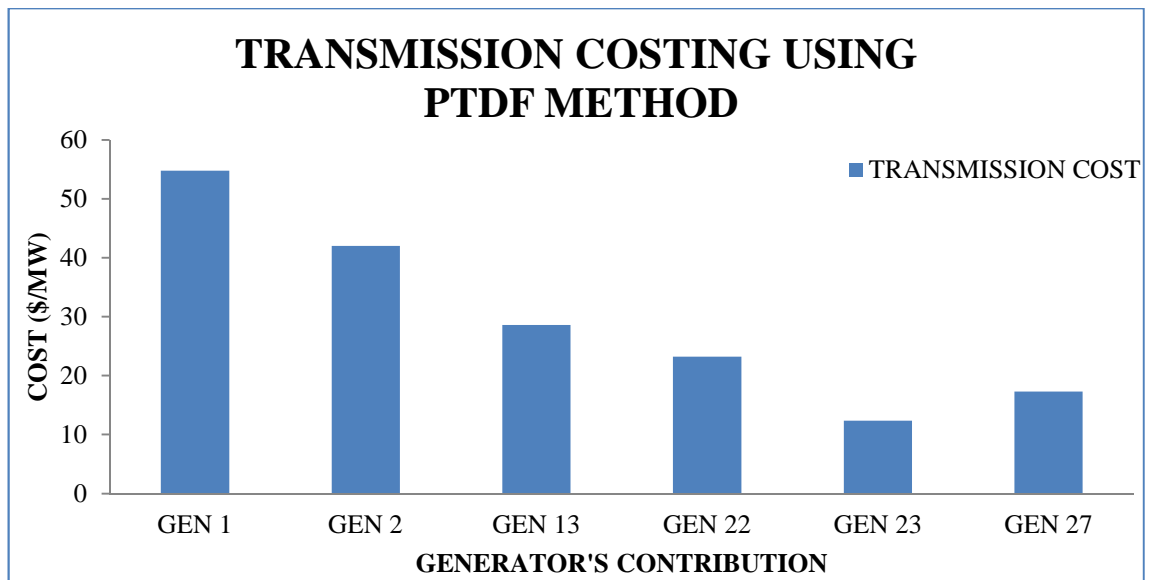


Figure 5.10: Bar Chart showing Transmission Costing using application of PTDF Method for IEEE 30-Bus System

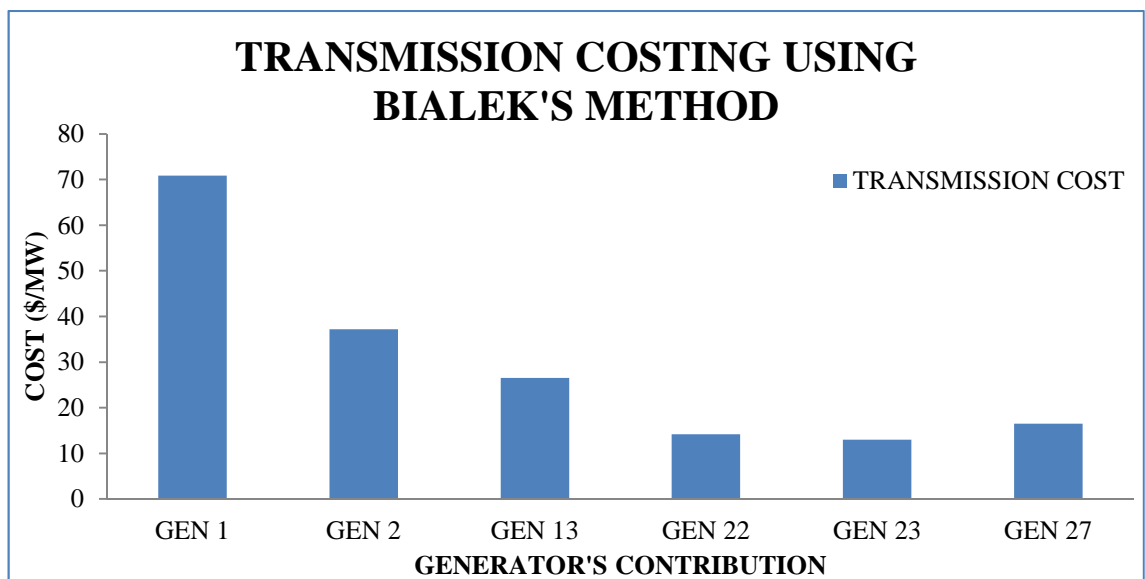


Figure 5.11: Bar Chart showing Transmission Costing using BIALEK'S Method for IEEE 30-Bus System

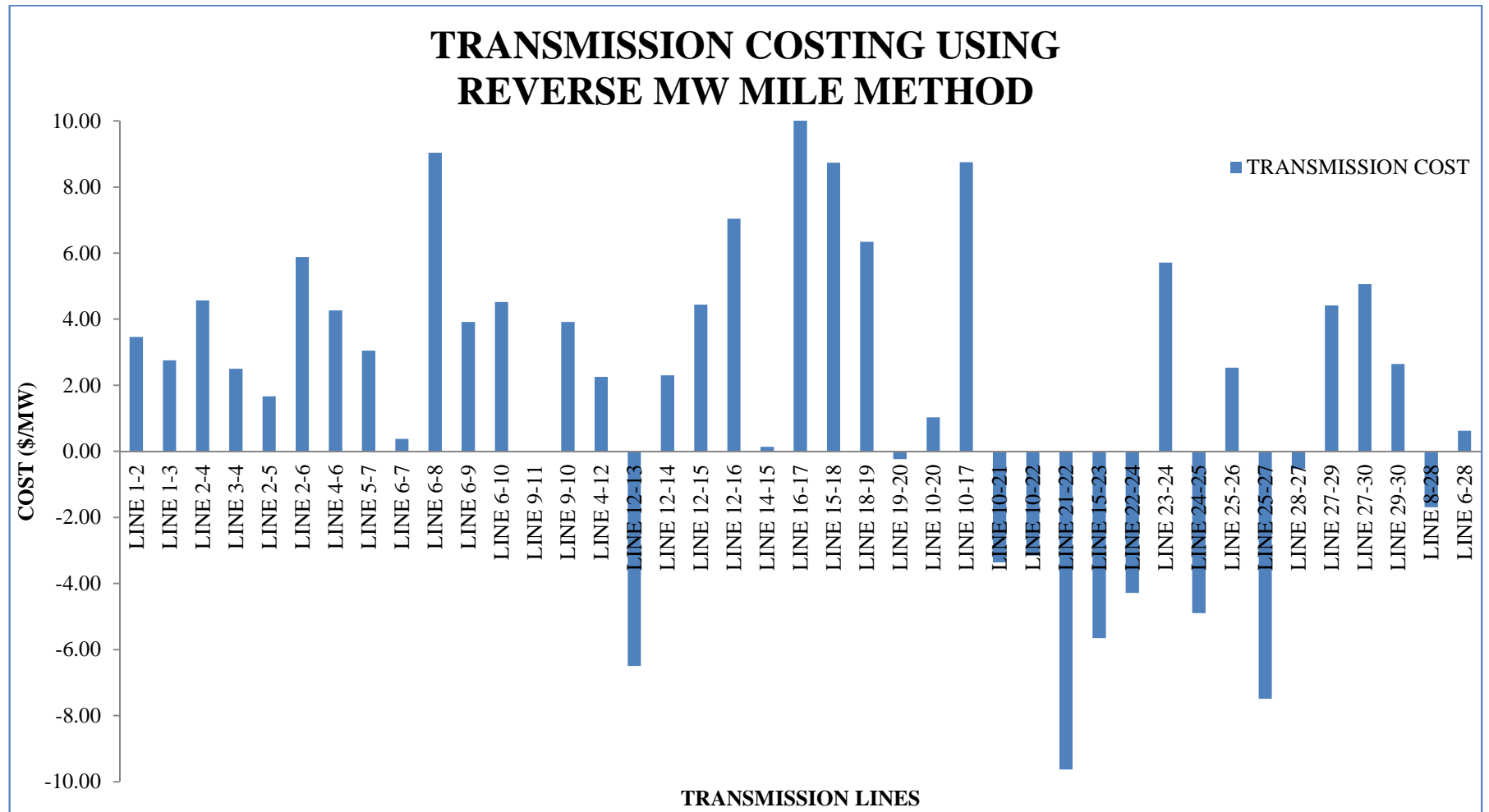


Figure 5.12: Bar Chart showing Transmission Costing using Reverse MW-Mile Method for IEEE 30-Bus System

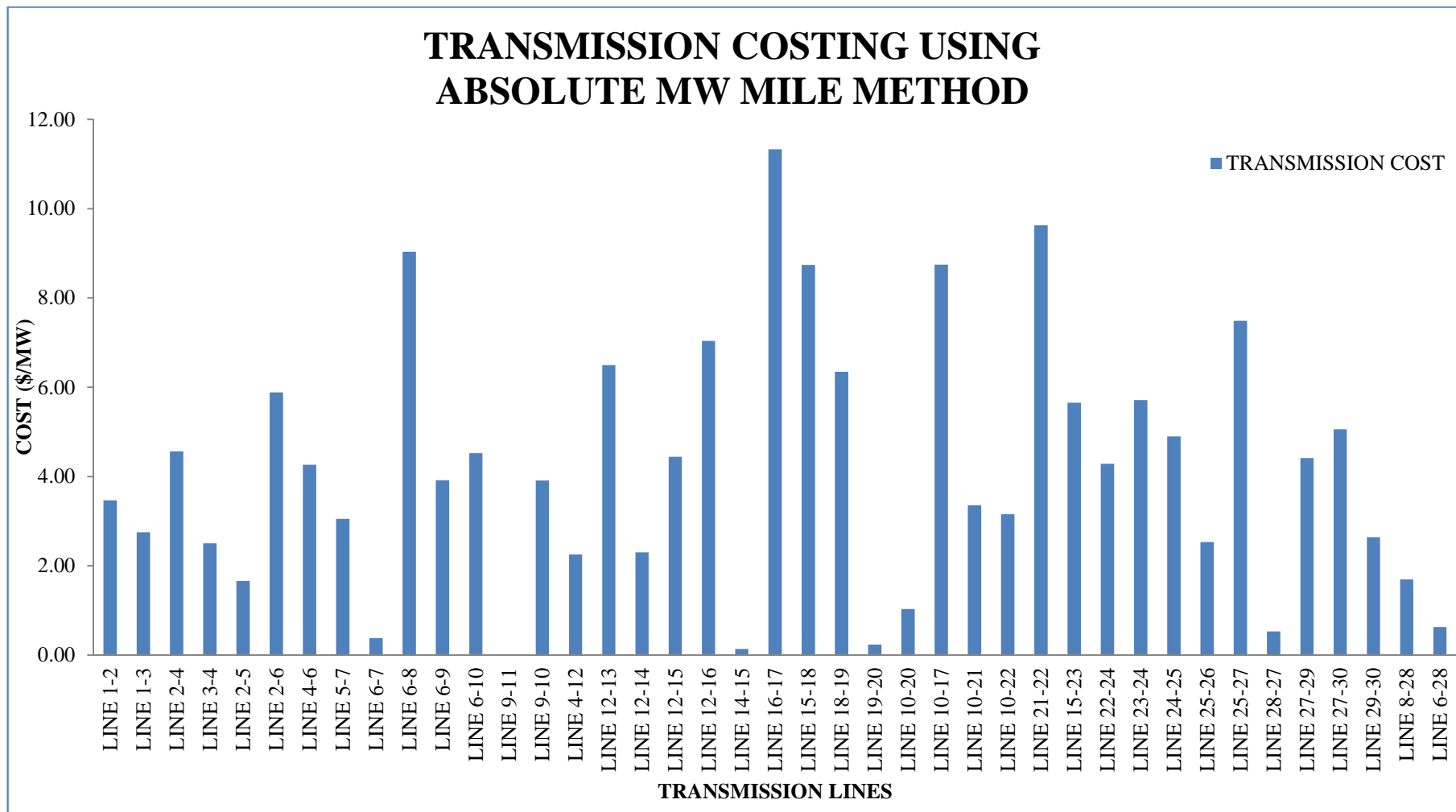


Figure 5.13: Bar Chart showing Transmission Costing using Absolute MW-Mile Method for IEEE 30-Bus System

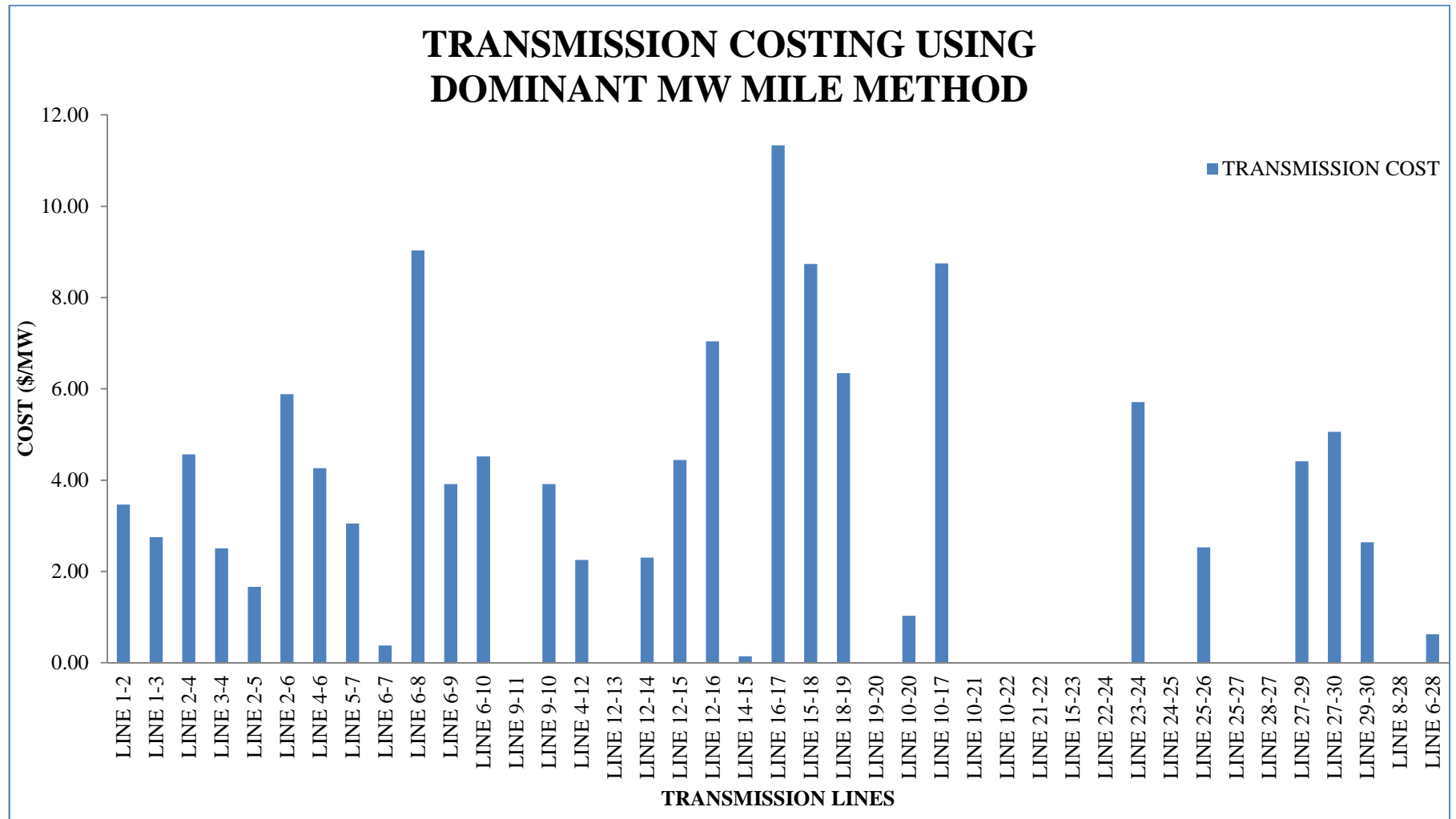


Figure 5.14: Bar Chart showing Transmission Costing using Dominant MW-Mile Method for IEEE 30-Bus System

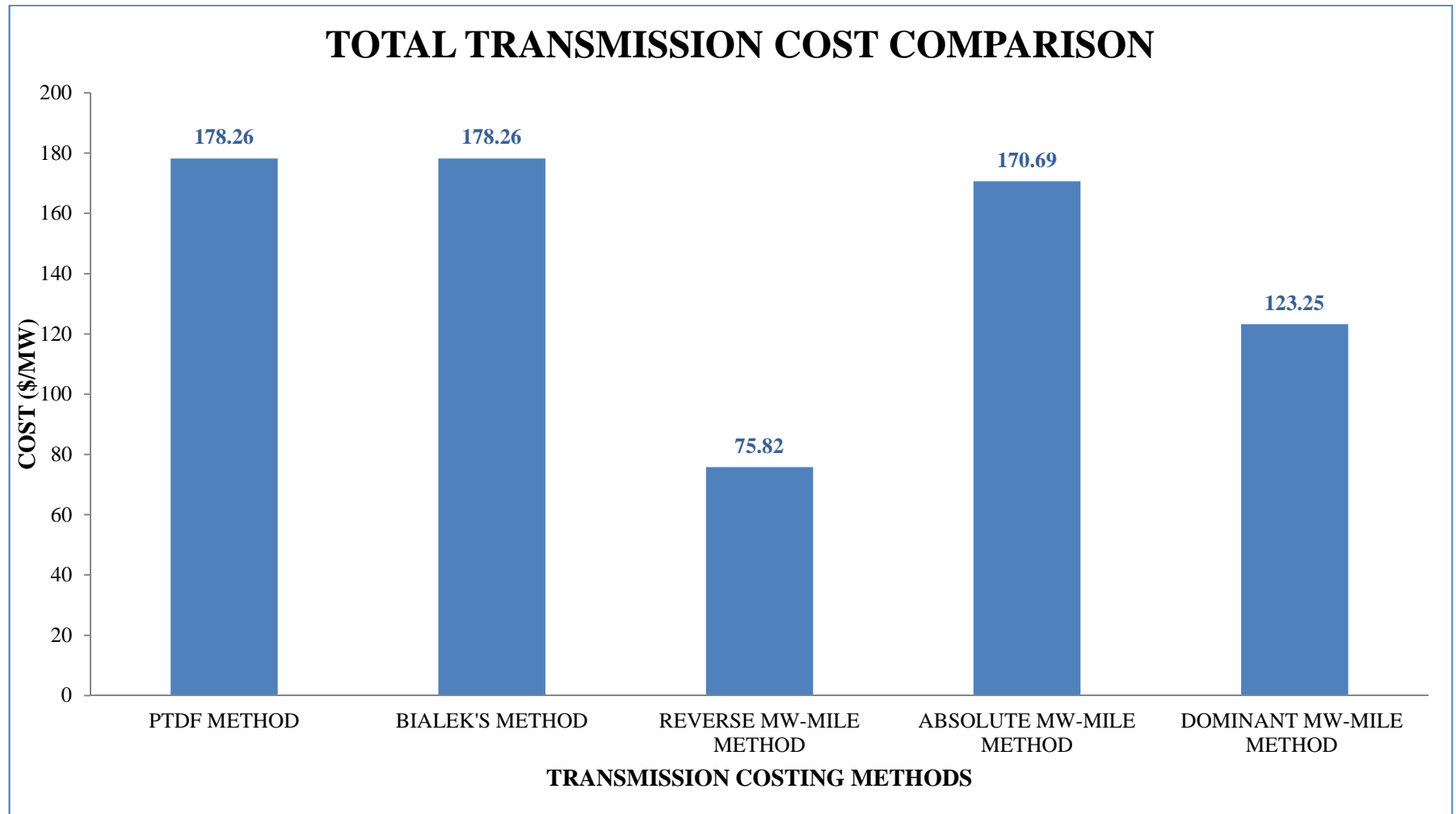


Figure 5.15: Bar Chart showing Total Transmission Cost Comparison for IEEE 30-Bus System

5.8.3 INDIAN UTILITY 146 - BUS SYSTEM

The total transmission Costing using the proposed application of PTDF method, Bialek's method, Reverse MW-Mile method, Absolute MW-Mile method and Dominant MW-Mile method are shown as bar charts in Figures 5.16, 5.17, 5.18, 5.19 and 5.20, the Total Transmission Cost comparison between all the methods used is shown in Figure 5.21.

Using the generator's contribution obtained from the proposed application of PTDF method and Bialek's method in Chapter 6, Transmission Costing is evaluated considering the Transmission line cost.

The obtained results for total transmission cost using proposed application of PTDF method is 1449.26 (\$/MW), which is slightly more than the cost obtained using Bialek's method which is 1118.23 (\$/MW). However, the Absolute MW Mile method gives a slightly smaller value i.e. 1154.62 (\$/MW). This comparison shows that the proposed application of PTDF method is justified and can be used for estimating the transmission cost of the transmission system. After analysing the cost obtained from all of the results it can be seen that the cost obtained from the proposed application of PTDF method is more than all the mentioned methods, so this method is also justified by obtaining sufficient revenue for the transmission system operators for maintenance as well as for future development.

Since the results for all the methods are comprehensive they are provided in table format in Appendix. E (CD enclosed).

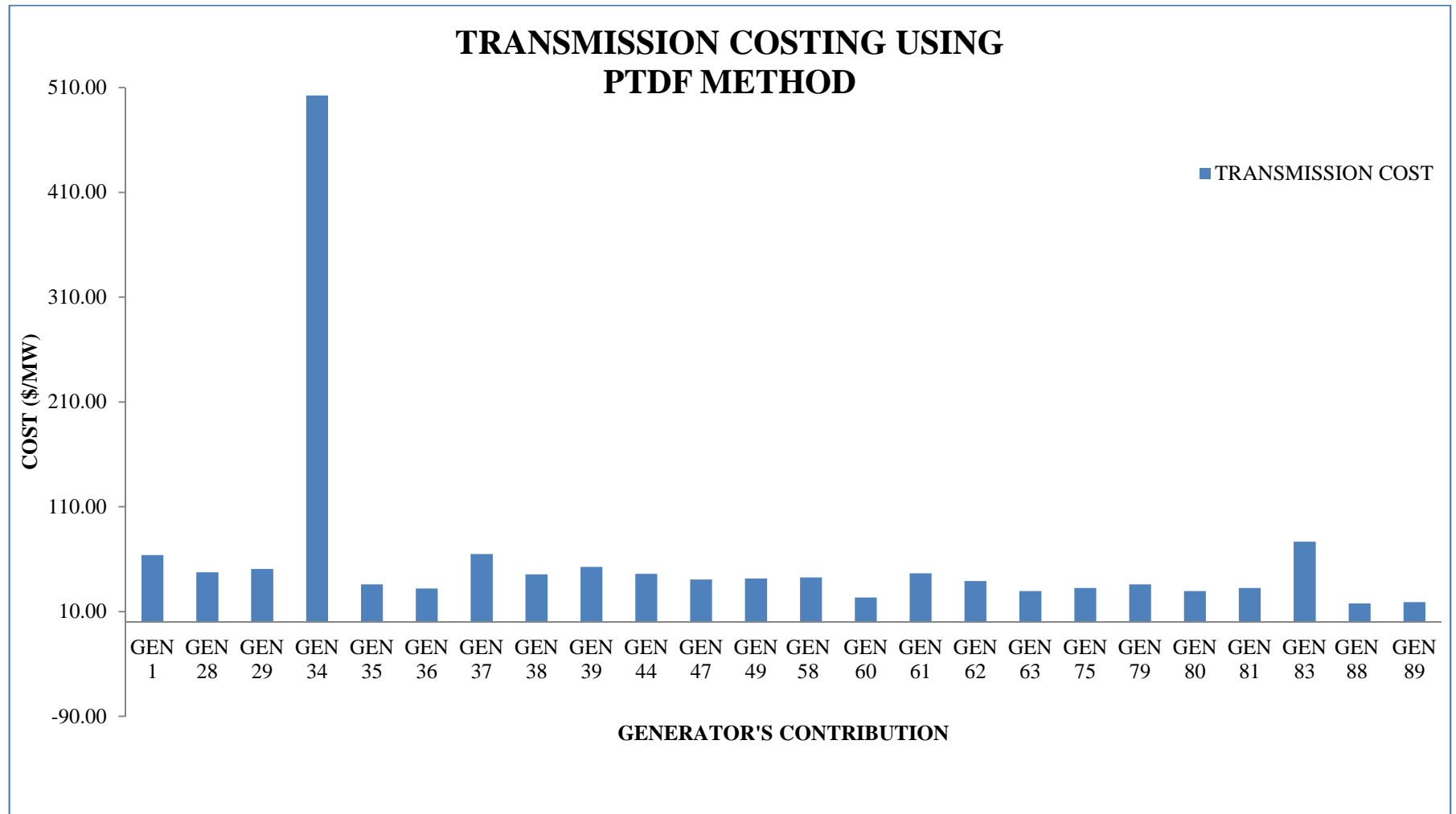


Figure 5.16: Bar Chart showing Transmission Costing using application of PTDF Method for Indian Utility 146-Bus System

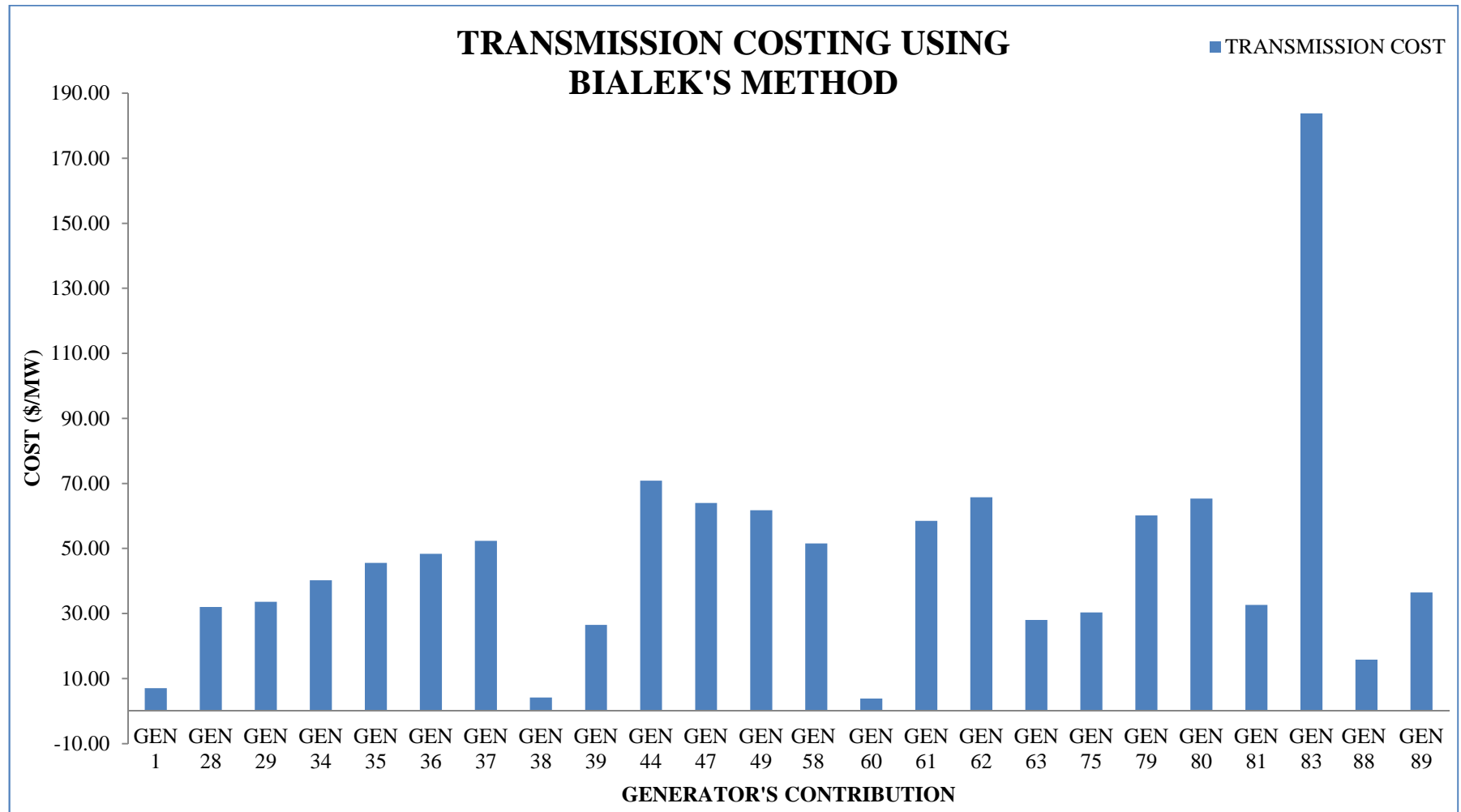


Figure 5.17: Bar Chart showing Transmission Costing using BIALEK'S Method for Indian Utility 146-Bus System

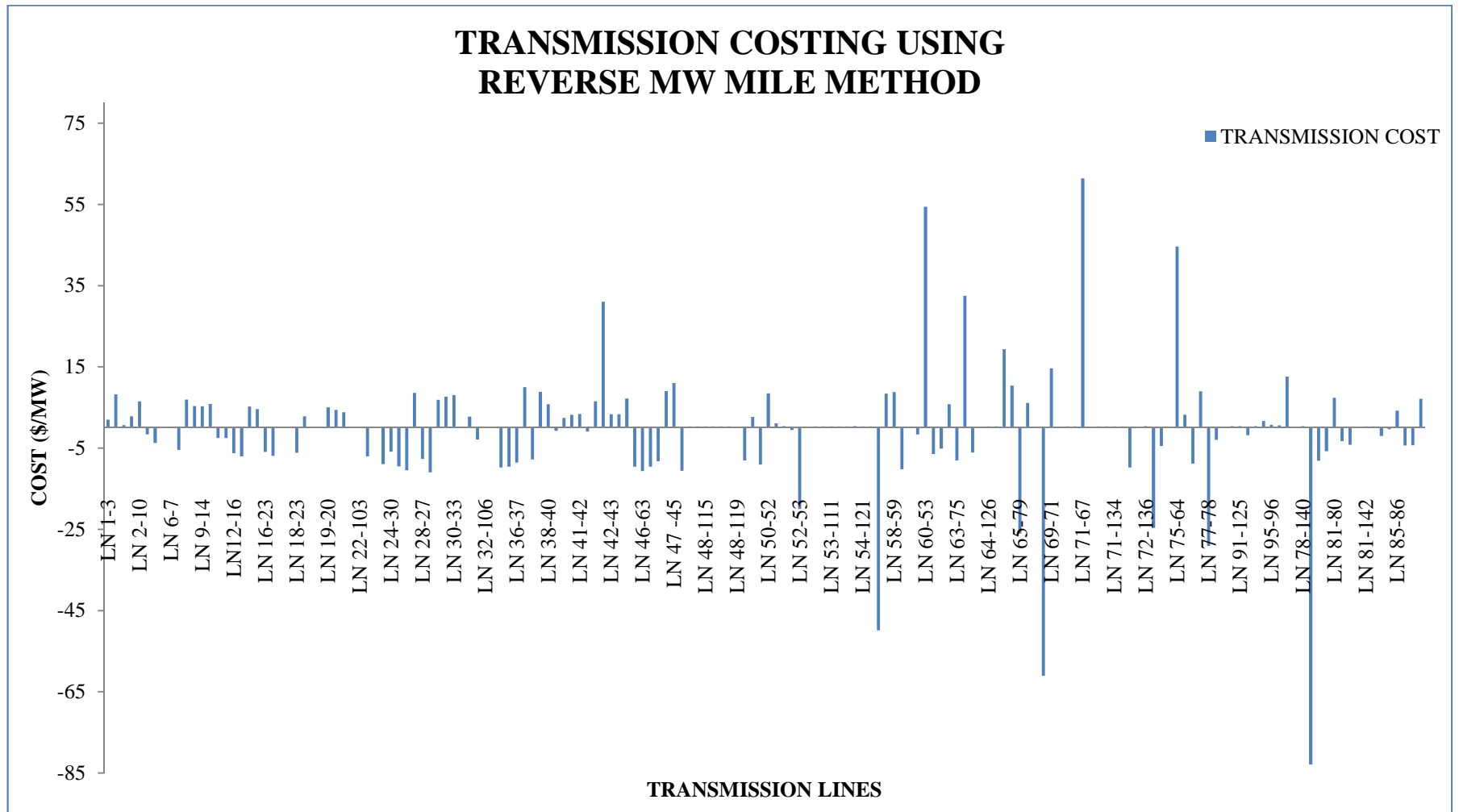


Figure 5.18: Bar Chart showing Transmission Costing using Reverse MW-Mile Method for Indian Utility 146-Bus System

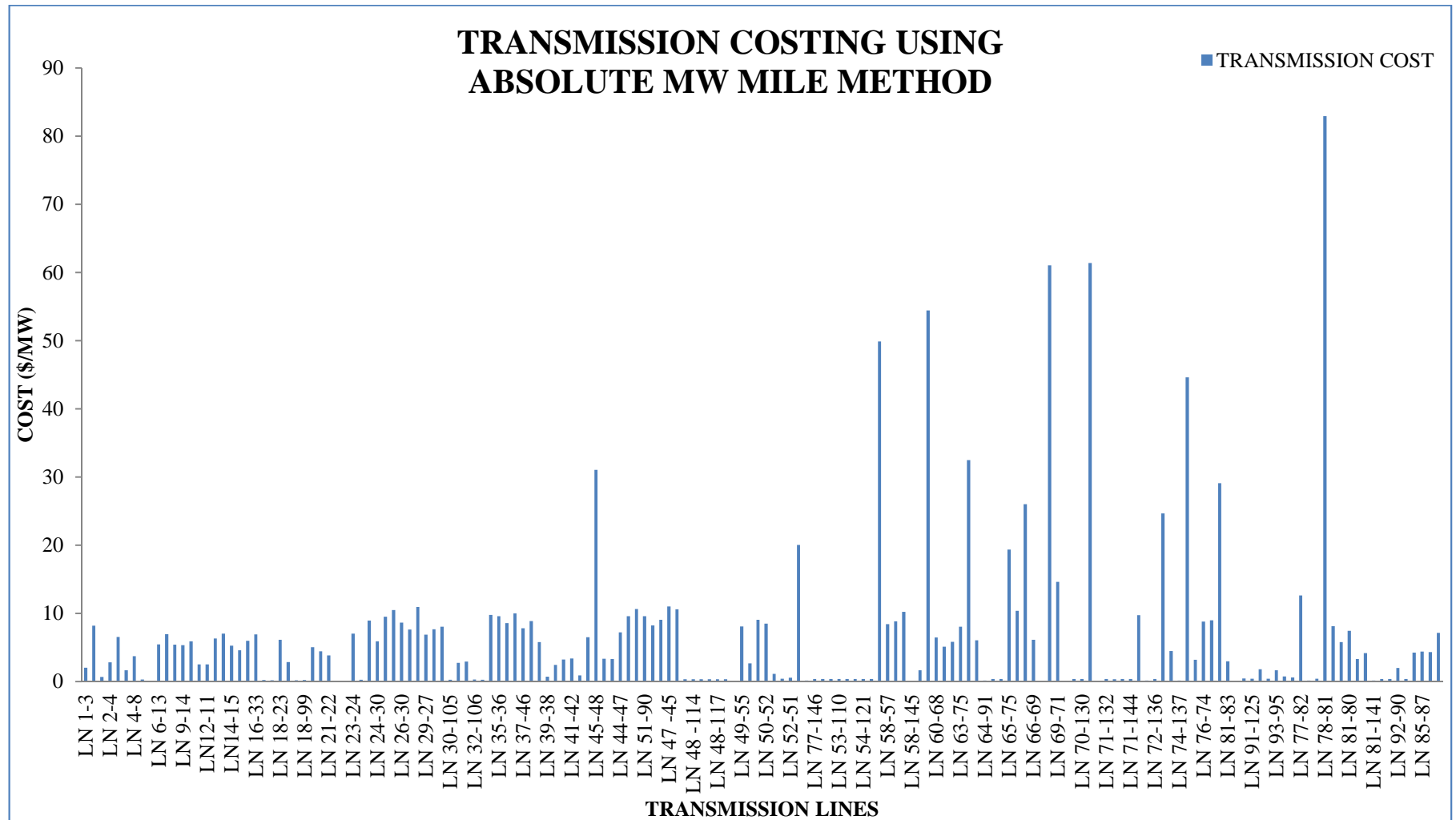
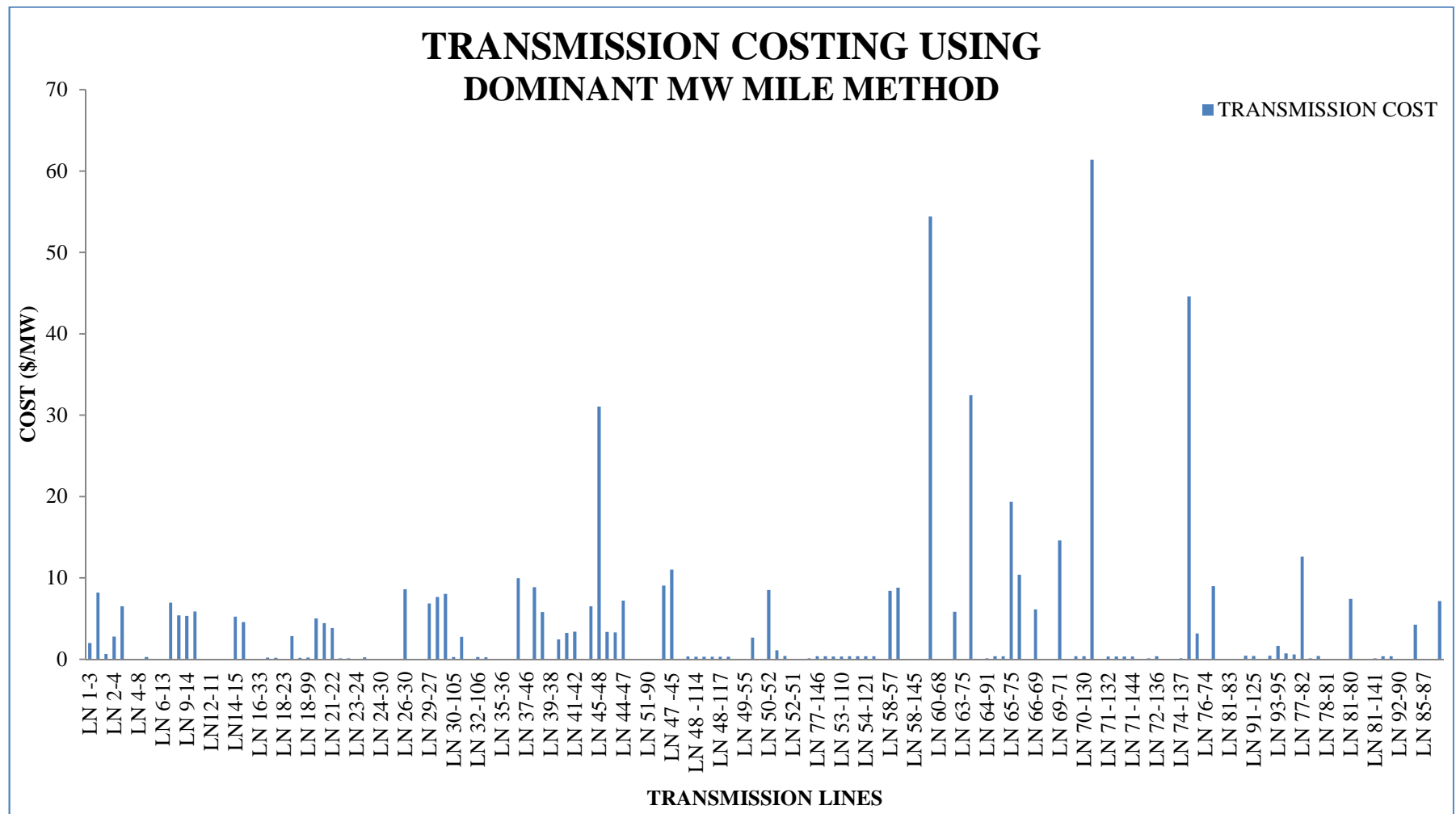


Figure 5.19: Bar Chart showing Transmission Costing using Absolute MW-Mile Method for Indian Utility 146-Bus System



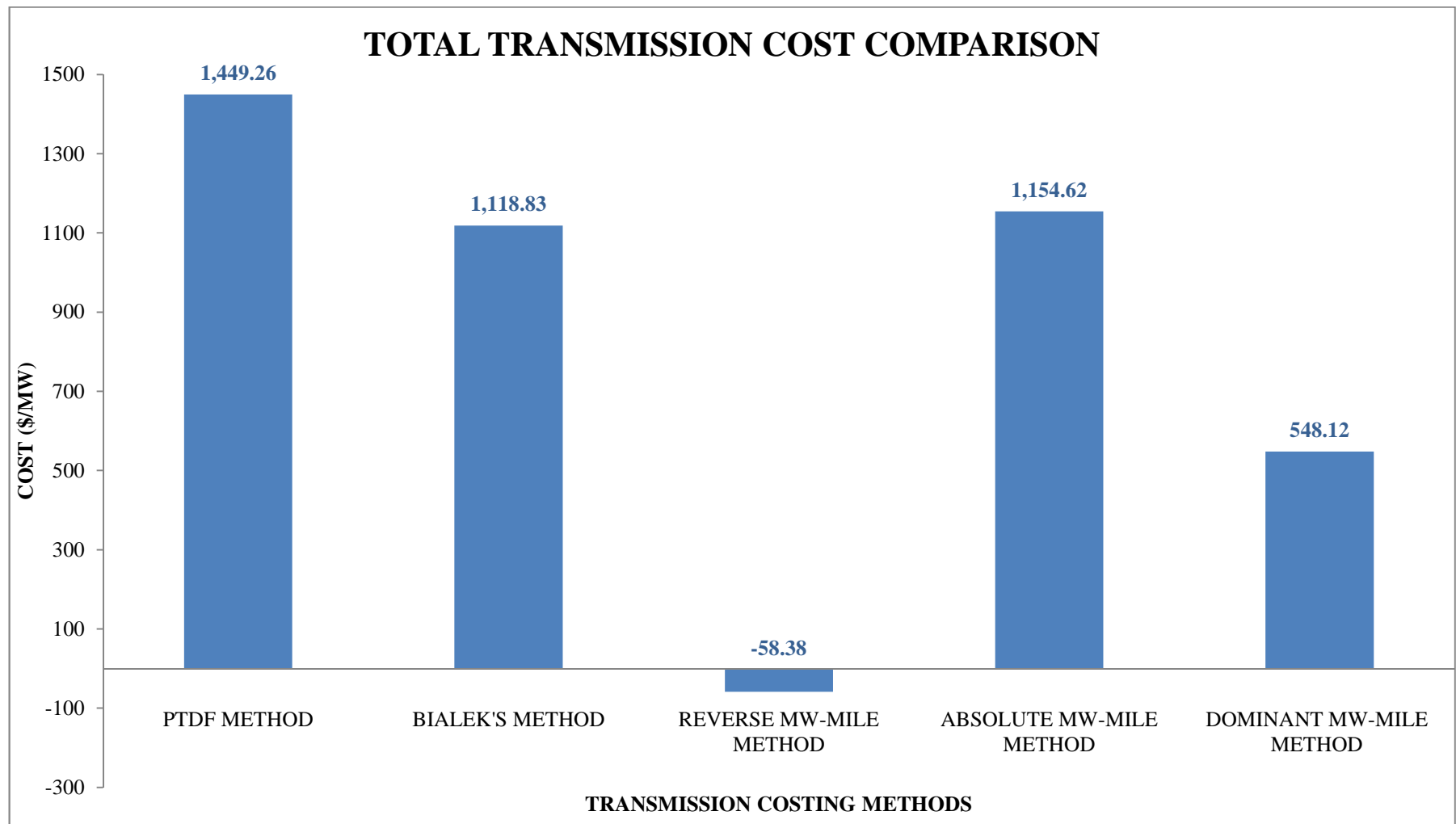


Figure 5.21: Bar Chart showing Total Transmission Cost Comparison for Indian Utility 146-Bus System

5.9 SUMMARY

As the proposed application of PTDF method, resulting in 78.73 (\$/MW) (for 7-bus), 178.26 (\$/MW) (for 30-bus) and 1449.26 (\$/MW) (for 146-bus), considers the complete (positive or negative) contribution of generators on transmission line while Bialek's method resulting in 59.23 (\$/MW) (for 7-bus), 178.26 (\$/MW) (for 30-bus) and 1118.23 (\$/MW) (for 146-bus), only considers upstream or downstream generator contributions, so the results obtained from Bialek's method will not provide the complete transmission cost. Whereas the results of 71.34 (\$/MW) (for 7-bus), 170.69 (\$/MW) (for 30-bus) and 1154.62 (\$/MW) (for 146-bus), obtained from using the Absolute MW Mile method consider the contribution from all generators either positive or negative i.e it takes into account the actual use of transmission capacity. After comparing Absolute MW Mile method with the proposed application of PTDF method it has been concluded that the proposed application of PTDF method gives similar results and can be used to calculate the embedded cost of the transmission system and it is considered to be justified and acceptable. The negative transmission cost for some generators and transmission line is due to power flow in opposite direction of the actual power flow.

It is demonstrated that as the proposed application of PTDF method used in the DMF for ROTC gives the complete cost of transmission (without Reserve Capacity) it can be used in the Indian transmission pricing schemes, as this is not too complicated to implement and the revenue collection is sufficient for the future growth and development of the Indian transmission network. Finally as stated in the previous sections we have presented summary results and relevant analysis with the detailed

results and the MATLAB program codes for the studies and simulations conducted in the relevant Appendices due to their large volume.

CHAPTER - 6

CONGESTION COSTING

6.1 INTRODUCTION

The major issue in terms of security in power system is Congestion Management. This is the condition when economic dispatch of the system gets changed in order to stabilize the system. The main reason for congestion in Transmission networks is due to violation of some power system constraints (Christie, Wollenberg 2000, Shirmohammadi 1998). The occurrence of congestion effects transmission pricing and thus decreases the overall efficiency of the system (Singh, David 2000) . This explains why it is very important to manage congestion and also to charge the network consumers who are responsible.

6.2 METHODS FOR PRICING CONGESTION

The congestion cost is calculated using three processes:

- Re-dispatch of generators
- Cost allocated for congestion constraints
- Contribution of load

Initially, ISOs check for any violation of constraints and the cause for congestion in the system. If the congestion is found to be due to constraints violation then the re-dispatch of generation is carried out to relieve the congestion. The Total Congestion Cost (TCC) is estimated as the difference between the production cost before and after re-dispatch. Thereafter, the contribution of each load for line flow is estimated using the proposed PTDF method application and Bialek's tracing method and the congestion cost for each load is calculated. They are then assigned and collected

from each load and paid to generator companies for the re-dispatch operation undertaken to eliminate congestion.

6.2.1 RE-DISPATCH OF GENERATORS

Under this method an OPF is utilized for re-dispatching of generators considering the constraints and the congestion is removed by regulating the generator output (MW).

OPF considers both equality and inequality constraints. Equality constraints include power balance equations, voltage limits etc. and the inequality constraints include generator's output, transmission line MVA (Mega-Volt Ampere) flow etc. All the Equality constraints and some of the inequality constraints like maximum active power flow have to be satisfied. The primary aim of OPF is to minimize the production cost or to adjust the generators output considering both equality and inequality constraints for a congestion free transmission system.

The function is,

$$\min \sum_{i=1}^n C_i (P_{Gi}) = \sum_{i=1}^n (a_i * P_{Gi}^2 + b_i * P_{Gi} + c_i) \text{ (Generation cost) (6.1)}$$

$$[P_G] - [P_D] = [B][\theta] \text{ (Equation for power Balance) (6.2)}$$

$$P_{ij} \leq P_{ij}^{max} \text{ where } P_{ij} = \frac{1}{x_{ij}} (\theta_i - \theta_j) \text{ (Limits for line flow) (6.3)}$$

$$P_{Gmin} \leq P_G \leq P_{Gmax} \text{ (Active power limits for generators) (6.4)}$$

Where, a_i, b_i, c_i are cost coefficients for generator at bus 'i', $C_i(P_{Gi})$, is the generator cost, (P_{Gi}) is the generated power at bus 'i', P_D is the power demand, θ_i is the voltage angle at bus 'i', x_{ij} is the i-j line reactance and P_{ij} is the power flow at line i-j.

The Susceptance Matrix 'B' is estimated from the following criteria,

$$[B] = \begin{cases} B_{ij} = \sum_j \frac{1}{x_{ij}} & \text{for } i \neq ref \\ B_{ij} = 0.0 & \text{for } i = ref \\ B_{ij} = \frac{-1}{x_{ij}} & \text{for } i \neq ref ; j \neq ref \\ B_{ij} = 0.0 & \text{for } i = ref ; \text{ for } j = ref \end{cases} \quad (6.5)$$

During the re-dispatch process the active power flow constraint is considered due to which the production cost of generators tend to increase. This increase in generator's production cost is called the Total Congestion Cost (TCC).

6.2.2 COST ALLOCATED FOR CONGESTION CONSTRAINTS

It is difficult to allocate the TCC to the congestion caused by multiple lines in the network and it is also not fair to charge all the congested lines equally as some lines are more responsible for congestion compared to others.

So a method has been developed to charge congested lines according to their contribution. In this method the effect of any line i-j is calculated by removing it from the system and this impact is known as the Relief cost. This method considers the following:

- Total cost of production with all lines is calculated.
- Relief cost for all the lines i-j are calculated.
- The constrained allocation cost is calculated based on proportional sharing principle using TCC.

$$TC_{ij} = \frac{RC_{ij} * (P_{ij} - P_{max})}{\sum_{ij} RC_{ij} * (P_{ij} - P_{max})} * TCC \quad (6.6)$$

where, $(P_{ij} - P_{max})$ is the minimum MW relief needed in order to relieve congestion.

6.2.3 CONTRIBUTION OF LOAD

Contribution of load for congestion is charged using load distribution factors. The method to determine Distribution factors is explained in Chapter 5 (Transmission Pricing) under Bialek's pricing method. These factors $D_{ij,k}^n$ are estimated for each load and line flows and the power contribution of each load for congestion in the line

is calculated as $D_{ij,k}^n * P_{Lk}$. Using this method the distance between load and the congested lines can be calculated as,

$$\text{Distance} = 1/\text{D-factor} \quad (6.7)$$

Application Method for congestion pricing:

- I. An unconstrained load flow is run for base case. Generators are re-dispatched for any constraints violation.
- II. OPF is run to eliminate congestion by re-dispatching generators.
- III. The production costs of generators are calculated for constrained and unconstrained cases.

$$PC_k = a * P_{Gk}^2 + b * P_{Gk} + c \quad (\text{Unconstrained}) \quad (6.8)$$

$$PC'_k = a * P_{Gk}'^2 + b * P_{Gk}' + c \quad (\text{Constrained}) \quad (6.9)$$

a, b, c are cost coefficients for generator

- IV. TCC is calculated taking difference between constrained and unconstrained cost of production

$$TCC = PC'_k - PC_k \quad (6.10)$$

- V. Then a Constrained allocation cost (TC) is calculated for each congested line.
- VI. Distribution factors are estimated for a line flow after re-dispatching the generators.
- VII. Power load contribution to each congested line is evaluated using:

$$D_{ij,k}^n * P_{Lk} \quad (6.11)$$

- VIII. The congestion cost due to each load is calculated as:

$$CC_k = \sum \frac{D_{ij,k}^n * P_{Lk}}{\sum_k (D_{ij,k}^n * P_{Lk})} * (TC_{ij}) \quad (6.12)$$

- IX. Incremental congestion Cost (ICC) which is the amount of change in congestion cost for any change in load(MW), is calculated as:

$$ICC_k = \frac{CC_k}{P_{Lk}} \quad (6.13)$$

This method charges the user according to their actual contribution for congestion in the congested lines. In this method ICC gives the load impact for its congestion cost.

ICC is proportional to the distance between congested lines and load i.e. ICC will be less for the distant load location.

6.3 FLOW CHART FOR CONGESTION COSTING

The following Flow Chart shown in Figure 6.1 explains the process and DMF for calculation of congestion cost using the proposed application of PTDF and Bialek's method which are further used for the verification of the proposed application of PTDF method. The Matlab programming codes used to achieve the objective for this part are given in Appendix-D.

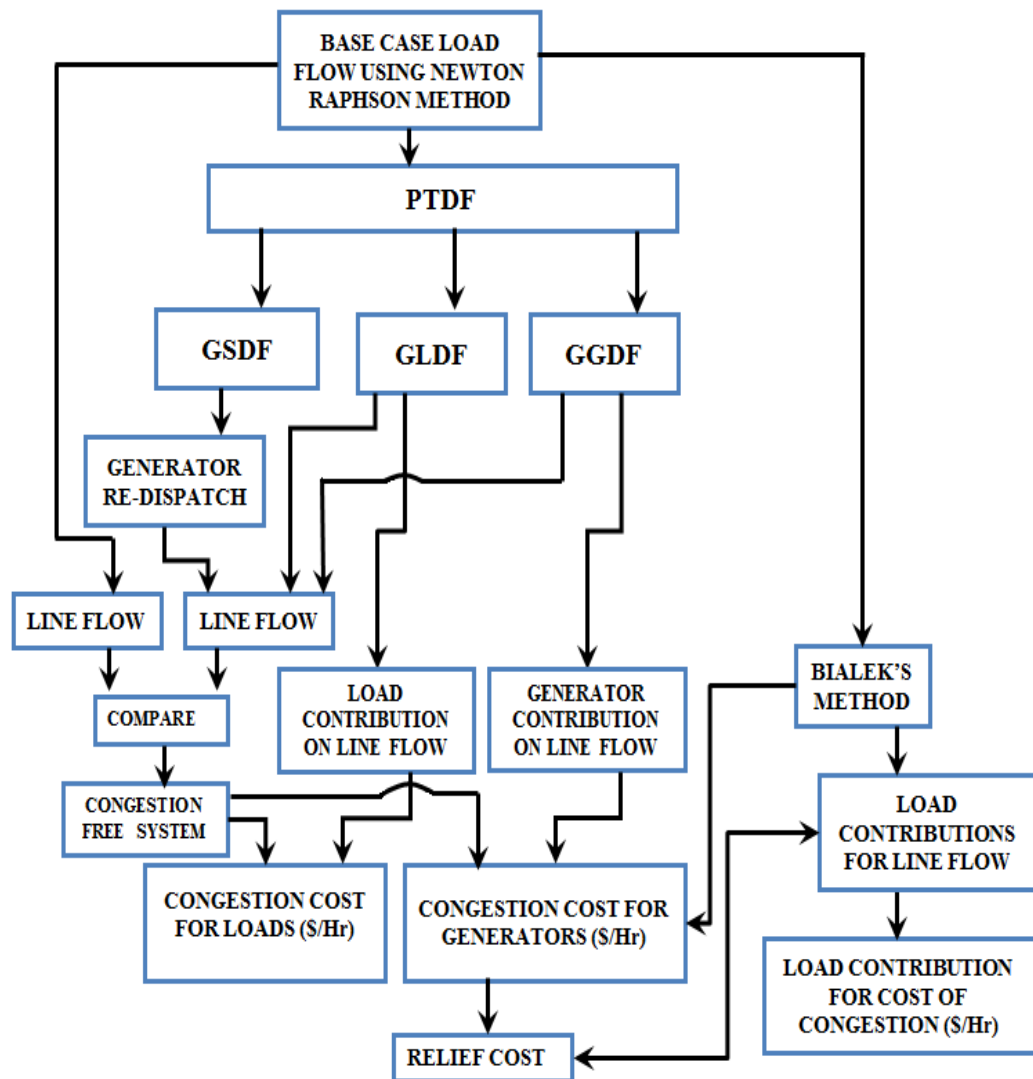


Figure 6.1: Flow Chart for Congestion Costing using proposed application of PTDF Method.

6.4 CASE STUDIES: COMPARISON OF PROPOSED APPLICATION OF PTDF AND BIALEK'S METHOD

In the competitive electrical market the Transmission network plays an important role in providing electrical energy from source to the consumers. The condition of transmission line congestion is the most controversial issue in the present deregulated electrical power system network. The congestion of transmission lines effects the normal operation of the transmission network. To avoid this situation two steps can be taken. The first is to have preventive solutions so that congestion can be avoided and secondly, to charge the consumers who are responsible for the congestion in the transmission network in order to discourage the consumers from over loading the network.

In this section three cases (7-Bus, IEEE 30-Bus and Indian Utility 146-Bus) have been evaluated using two methods. The obtained results from the proposed application of PTDF method are compared with Bialek's method.

The following results of Congestion costing for the 7-Bus case study is given below to verify the output of the proposed application of PTDF method with the published results in literature and these results were used as a part of procedure to calculate ROTC.

6.4.1 7-BUS SYSTEM

A 7-Bus system is shown in Figure 4.3 of Chapter 4. The system consists of six generators and five loads. The system has ten transmission lines. Some of the buses have both generators and loads connected. The line data, generator data, load data and line limits are given in Appendix-A.

After running a Newton-Raphson AC Load Flow three Transmission lines Line 1-2, Line 3-4 and Line 4-5 are found to be congested, which can be seen in Table 4.2. The aim of this case study is to find the contribution of generator and load on the Power Flow of these lines and then to assign the congestion price on the loads responsible for the congestion in these lines. Two cases are considered for the analysis:

Case 1: Unconstrained case, where no transmission limits is considered for any Power transmission.

Case 2: Constrained case, where transmission limits are applied for transmission of power.

The power flows for both the cases are given in the Table 4.2 and Table 4.4 of Chapter-4. The Line flow of the transmission line in the constrained case has been changed after re-dispatch of generators and that is shown in Table 4.4 of Chapter-4.

The total generation cost is determined for constrained and unconstrained cases. The constraint is taken as the Line limits. A corrective action policy is considered for relieving the congestion of overloaded lines. This can be achieved by redispatching the generators, which is performed by using GSDF. To lower the power flow in the transmission lines according to line limits the GSDF for the near generators are considered and if the value is negative then the generation is increased for that generator and if the GSDF is positive for another near generator then the generation is reduced for that generator using Equation 6.14,

$$\Delta P_{gi} = \frac{\Delta F_{i-j}}{A_{i-j,i}} \quad (6.14)$$

Where, i and j are the buses, ΔP_{gi} is the change in generation, ΔF_{i-j} is the line flow to be changed and $A_{i-j,i}$ is the GSDF.

The PTDF has been calculated using Power flow by programming in MATLAB and the results are shown in Table: 6.1. From the obtained PTDF, other distribution factors like GGDF and GLDF are also determined which are shown in Table 6.2 and Table 6.3.

Table 6.1: Power Transfer Distribution Factor (PTDF) calculated for 7-Bus System

PTDF							
LINES		BUS NUMBER					
FROM	TO	BUS 2	BUS 3	BUS 4	BUS 5	BUS 6	BUS 7
1	2	-0.70	-0.37	-0.62	-0.65	-0.68	-0.67
1	3	-0.30	-0.63	-0.38	-0.35	-0.32	-0.33
2	3	0.22	-0.26	0.10	0.16	0.20	0.18
2	4	0.05	-0.06	-0.45	-0.21	-0.03	-0.11
2	5	0.02	-0.02	-0.18	-0.40	-0.11	-0.24
2	6	0.01	-0.01	-0.09	-0.20	-0.75	-0.51
3	4	-0.08	0.10	-0.28	-0.19	-0.12	-0.15
4	5	-0.03	0.04	0.27	-0.40	-0.14	-0.26
7	5	0.01	-0.01	-0.09	-0.20	0.25	0.49
6	7	0.01	-0.01	-0.09	-0.20	0.25	-0.51

The GGDF's gives the impact of each generator on the active power flow on any line. They are calculated using Equations 6.15, 6.16 and 6.17:

$$F_{j-k} = \sum_{i=1}^n D_{j-k,i} * G_i \quad (6.15)$$

$$\text{Where, } D_{j-k,i} = D_{j-k,r} + PTDF_{j-k,i} \quad (6.16)$$

$$D_{j-k,r} = \frac{\left\{ F_{j-k}^0 + \sum_{i \neq r}^n PTDF_{j-k,i} * G_i \right\}}{\sum_{i=1}^n G_i} \quad (6.17)$$

F_{j-k} : Total active power flow between buses j and k

$D_{j-k,i}$: GGDF of line between buses j & k corresponding to generator at bus 'i'

G_i : Generation at bus 'i'

F_{j-k}^0 : Power flow between j & k from previous iteration

$D_{j-k,r}$: GGDF of line between buses j & k due to generator at reference bus 'r'

The calculated GGDF's are shown in Table 6.2. The generators are at Bus-1, Bus-2, Bus-4, Bus-6 and Bus-7.

Table 6.2: Generalised Generator Distribution Factor (GGDF) calculated for 7-Bus System

LINES		GGDF				
FROM	TO	D1=REF LINE FLOW/GEN AT SLACK BUS	D2=D1+ PTDF 2	D4=D1+ PTDF 4	D6=D1+ PTDF 6	D7=D1+ PTDF 7
1	2	0.78	0.09	0.17	0.10	0.11
1	3	0.22	-0.09	-0.17	-0.10	-0.11
2	3	0.03	0.25	0.13	0.23	0.21
2	4	0.04	0.10	-0.41	0.01	-0.07
2	5	0.24	0.26	0.06	0.13	0.00
2	6	0.33	0.34	0.24	-0.42	-0.18
3	4	0.10	0.01	-0.18	-0.02	-0.05
4	5	0.09	0.06	0.36	-0.05	-0.17
7	5	-0.16	-0.15	-0.25	0.09	0.33
6	7	0.08	0.09	-0.01	0.33	-0.43

The GLDF's gives the impact of each load on the active power flow on any line and can also be negative. They are calculated using the equation:

$$F_{j-k} = \sum_{i=1}^n C_{j-k,i} * L_i \quad (6.18)$$

Where, $C_{j-k,i} = C_{j-k,r} - PTDF_{j-k,i}$ (6.19)

$$C_{j-k,r} = \frac{\left\{ F_{j-k}^0 + \sum_{i \neq r}^n PTDF_{j-k,i} * L_i \right\}}{\sum_{i=1}^n L_i} \quad (6.20)$$

F_{j-k} : Total active power flow between buses j and k

$C_{j-k,i}$: GLDF of line between buses j & k corresponding to generator at bus 'i'

L_i : Load Demand at bus 'i'

F_{j-k}^0 : Power flow between j & k from previous iteration

$C_{j-k,r}$: GLDF of line between buses j & k due to generator at reference bus 'r'

The calculated GLDF's are shown in Table 6.3.

Table 6.3: Generalised Load Distribution Factor (GLDF) calculated for 7-Bus System

LINES		GLDF						
FROM	TO	Cr	C2	C3	C4	C5	C6	C7
1	2	-0.45	0.24	-0.09	0.17	0.20	0.23	0.22
1	3	-0.31	0.00	0.33	0.08	0.04	0.01	0.02
2	3	0.15	-0.07	0.42	0.05	-0.01	-0.05	-0.03
2	4	-0.08	-0.13	-0.01	0.38	0.14	-0.05	0.03
2	5	-0.02	-0.04	0.00	0.16	0.38	0.09	0.22
2	6	-0.33	-0.34	-0.31	-0.23	-0.12	0.42	0.18
3	4	-0.16	-0.07	-0.26	0.12	0.03	-0.04	-0.01
4	5	-0.10	-0.07	-0.14	-0.37	0.30	0.04	0.16
7	5	0.13	0.12	0.14	0.22	0.33	-0.13	-0.37
6	7	-0.04	-0.05	-0.02	0.06	0.17	-0.29	0.47

Using distribution factors obtained from PTDF, the load and generation contributions to line flow have been determined and are given in Table 6.4 and Table 6.5. Also the generators' and loads' contributions on line flow and each other are also determined

using Bialek's method, which are shown in Table 6.6, Table 6.7, Table 6.8 and Table 6.9.

Table 6.4: Load Contribution on Line Flow for 7-Bus system using application of PTDF Method

LOAD'S CONTRIBUTION ON LINE FLOW USING PTDF METHOD								
LINES		LOAD 2	LOAD 3	LOAD 4	LOAD 5	LOAD 6	LOAD 7	TOTAL LINE FLOW
FROM	TO	MW	MW	MW	MW	MW	MW	MW
1	2	19.51	-9.53	6.60	26.33	46.24	43.69	132.84
1	3	-0.10	36.22	3.10	5.21	2.29	4.83	51.55
2	3	-5.57	45.67	1.84	-1.17	-10.19	-6.46	24.13
2	4	-10.33	-1.47	15.04	17.63	-9.53	6.76	18.09
2	5	-3.36	0.39	6.26	48.96	17.37	43.13	112.77
2	6	-26.88	-34.39	-9.37	-15.77	84.48	36.15	34.22
4	3	-5.79	-28.27	4.89	3.85	-8.21	-1.93	-35.47
4	5	-5.61	-15.29	-14.82	38.55	8.53	31.10	42.46
5	7	9.30	15.36	8.72	43.02	-25.07	-73.40	-22.07
6	7	-3.74	-2.57	2.20	21.83	-57.67	94.00	54.06

Table 6.5: Generator Contribution on Line Flow for 7-Bus system using application of PTDF Method

GENERATOR'S CONTRIBUTION ON LINE FLOW USING PTDF METHOD								
LINES		TOTAL LINE FLOW	GEN 1	GEN 2	GEN 4	GEN 6	GEN 7	TOTAL
FROM	TO	MW	MW	MW	MW	MW	MW	MW
1	2	132.84	144.37	12.04	16.62	22.00	14.09	209.13
1	3	51.55	40.01	-12.05	-16.62	-22.01	-14.09	-24.76
2	3	24.13	4.88	34.07	13.11	50.20	26.19	128.46
2	4	18.09	7.91	13.18	-40.95	3.09	-8.43	-25.20
2	5	112.77	44.51	36.17	6.36	29.33	0.56	116.93
2	6	34.22	60.58	46.81	23.74	-92.22	-22.19	16.71
4	3	35.54	17.88	1.81	-18.15	-4.03	-6.21	-8.70
4	5	42.46	16.79	8.25	36.01	-11.68	-20.74	28.63
5	7	22.12	-29.76	-20.81	-25.26	19.98	41.56	-14.29
6	7	54.06	14.77	12.52	-1.11	73.12	-53.25	46.04
TOTAL		527.77						472.93

Table 6.6: Load Contribution on Line Flow for 7-Bus system using BIALEK'S Method

LOAD'S CONTRIBUTION ON LINE FLOW USING BIALEK'S METHOD									
FROM	TO	TOTAL LINE FLOW	LOAD 2	LOAD 3	LOAD 4	LOAD 5	LOAD 6	LOAD 7	TOTAL
			MW	MW	MW	MW	MW	MW	MW
1	2	132.84	28.80	47.54	2.21	35.93	9.70	8.66	132.84
1	3	51.55	11.17	18.45	0.86	13.94	3.76	3.36	51.55
2	3	24.13	7.25	2.66	0.56	9.04	2.44	2.18	24.13
2	4	18.09	5.43	2.00	0.42	6.78	1.83	1.63	18.09
2	5	112.77	33.87	12.45	2.60	42.26	11.40	10.19	112.77
2	6	34.22	10.28	3.78	0.79	12.82	3.46	3.09	34.22
4	3	35.54	0.00	10.75	12.12	10.82	0.00	1.84	35.54
4	5	42.46	0.00	12.85	14.49	12.93	0.00	2.20	42.46
5	7	22.12	0.00	0.00	0.00	18.91	0.00	3.21	22.12
6	7	54.06	0.00	0.00	0.00	0.00	42.75	11.31	54.06
TOTAL		527.77							527.77

Table 6.7: Generator Contribution on Line Flow for 7-Bus system using BIALEK'S Method

GENERATOR'S CONTRIBUTION ON LINE FLOW USING BIALEK'S METHOD								
LINES		TOTAL LINE FLOW	GEN 1	GEN 2	GEN 4	GEN 6	GEN 7	TOTAL
FROM	TO	MW	MW	MW	MW	MW	MW	MW
1	2	132.84	132.84	0.00	0.00	0.00	0.00	132.84
1	3	51.55	51.55	0.00	0.00	0.00	0.00	51.55
2	3	24.13	17.53	6.60	0.00	0.00	0.00	24.13
2	4	18.09	13.14	4.95	0.00	0.00	0.00	18.09
2	5	112.77	81.93	30.84	0.00	0.00	0.00	112.77
2	6	34.22	24.86	9.36	0.00	0.00	0.00	34.22
4	3	35.54	2.14	0.81	32.59	0.00	0.00	35.54
4	5	42.46	2.56	0.96	38.94	0.00	0.00	42.46
5	7	22.12	16.57	6.24	7.64	0.00	0.00	30.44
6	7	54.06	7.30	2.75	0.00	44.02	0.00	54.06
TOTAL		527.77						536.10

Table 6.8: Generator Contribution on Loads for 7-Bus system using BIALEK'S Method

GENERATOR'S CONTRIBUTION ON LOADS USING BIALEK'S METHOD						
BUS NUMBER WITH LOAD	GEN 1	GEN 2	GEN 4	GEN 6	GEN 7	TOTAL
	MW	MW	MW	MW	MW	MW
2	58.1	21.9	0	0	80	160
3	152	15.8	69.5	0	237.3	474.6
4	2.4	0.9	36.7	0	40	80
5	97.4	36.7	44.9	0	179	358
6	27	10.2	0	162.8	200	400
7	28.7	10.8	9.2	53	108.3	210

Table 6.9: Load Contribution on Generators for 7-Bus system using BIALEK'S Method

LOAD CONTRIBUTION ON GENERATORS USING BIALEK'S METHOD								
LOADS GENERATORS		LOAD 2	LOAD 3	LOAD 4	LOAD 5	LOAD 6	LOAD 7	TOTAL
		MW	MW	MW	MW	MW	MW	MW
GEN 1	300 MW	65.03	107.36	4.99	81.15	21.9	19.57	300
GEN 2	50 MW	15.02	5.52	1.15	18.74	5.06	4.52	50.01
GEN 4	200 MW	0	60.51	68.24	60.91	0	10.34	200
GEN 6	150 MW	0	0	0	0	118.61	31.39	150
GEN 7	90 MW	0	0	0	0	0	90	90

It can be seen from Table 6.10 using Bialek's Method that generation at buses 1 and 4 is reduced and generation at buses 2, 6 and 7 is increased during re-dispatch to relieve the congestion in the transmission lines. The increase in generation cost, which is also termed as the Total Congestion Cost (TCC) is given in Table 6.10 and also in the Bar chart in Figure 6.2 for complete analysis. The TCC for the 7-Bus system shown in Figure 6.2 is found to be 200.94 (\$/Hr).

Table 6.10: Congestion Cost and Total Congestion Cost of 7-Bus system using BIALEK'S Method

CONGESTION COST USING BIALEK'S METHOD					
GEN No.	GEN (MW)		COST (\$/Hr)		TCC(\$/Hr) CASE2-CASE1
	CASE 1	CASE 2	CASE 1	CASE 2	
1	283.50	184.38	2810.84	1934.48	-876.36
2	50.00	138.00	860.96	1588.56	727.60
4	200.00	100.00	1763.00	1070.63	-692.37
6	150.00	220.00	1790.33	2471.32	680.99
7	90.00	125.00	1198.86	1559.93	361.08
TOTAL			8423.99	8624.93	200.94

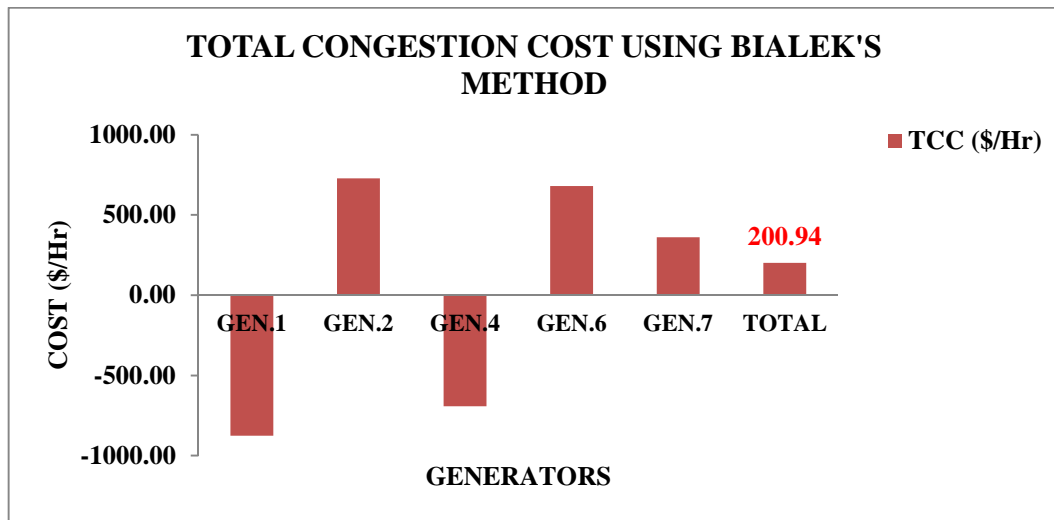


Figure 6.2: Bar Chart showing Total Congestion Cost of 7-Bus system using BIALEK'S Method

The TCC calculated after the re-dispatch of generators is assigned to all the congested lines according to their contribution to the congestion cost. It is important to evaluate the effect of congested lines on TCC so as to assign and distribute the congestion cost among the loads responsible for congestion. The impact of the congested lines is estimated by disconnecting the congested lines one by one and calculating the TCC for each case. This impact is known as the Relief Cost (RC)

which is the change in the generation cost after disconnecting a congested line and thus helps to apportion TCC among the congested lines.

The calculated Relief cost for three congested lines is as follows:

$$RC_{12} = 92.3 \text{ ($/Hr)}, RC_{34} = 38 \text{ ($/Hr)}, RC_{45} = 103.56 \text{ ($/Hr)},$$

So the calculated constrained allocation cost, which is the distribution of TCC among all lines using Equation 6.6 are,

$$TC_{12} = 139.48 \text{ ($/Hr)}, TC_{34} = 22.13 \text{ ($/Hr)}, TC_{45} = 44.58 \text{ ($/Hr)}$$

This can be verified from Table 6.11 and Figure 6.3. These constraint costs are divided among all the Loads responsible for congestion using the proposed PTDF method by calculating the Load Contribution on line Flow. And TCC is calculated taking the summation of all the TC's with respect to each load.

Table 6.11: Transmission Cost and Total Congestion Cost for 7-Bus system using application of PTDF Method

TRANSMISSION COST AND TOTAL CONGESTION COST USING PTDF METHOD							
LOAD	C*LOAD LINE 1-2	TC (\$/Hr)	C*LOAD LINE 4-3	TC (\$/Hr)	C*LOAD LINE 4-5	TC (\$/Hr)	TCC (\$/Hr)
80	19.51	20.49	-5.79	-6.08	-5.61	-5.90	8.51
110	-9.53	-10.01	28.27	29.68	-15.29	-16.06	3.62
40	6.60	6.93	4.89	5.13	-14.82	-15.56	-3.50
130	26.33	27.65	3.85	4.04	38.55	40.48	72.17
200	46.24	48.55	-8.21	-8.62	8.53	8.96	48.89
200	43.69	45.88	-1.93	-2.03	31.10	32.66	76.51
TOTAL	132.84	139.48	21.07	22.13	42.46	44.58	206.19

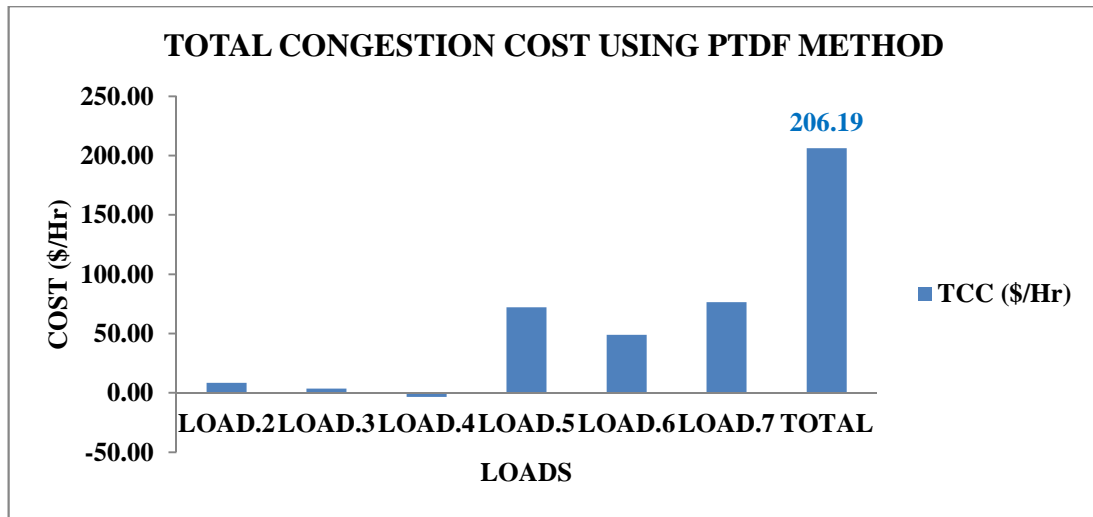


Figure 6.3: Bar Chart showing Total Congestion Cost for 7-Bus system using application of PTDF Method

By comparing the results obtained using the proposed PTDF method in Table 6.11, Figure 6.3 and Bialek's method in Table 6.10 and Figure 6.2, it is found that both the methods result in similar costs for total congestion i.e. according to Bialek's method the total congestion cost is 200.94(\$/Hr) and from the proposed PTDF method it is 206.19 (\$/Hr). From this it is verified that using the proposed application of PTDF method congestion costs can be estimated. Along with congestion costs, generator and load contributions to line flow can also be estimated close to actual values. The congestion cost for some lines are negative because after re-dispatch of generation the dispatch becomes more economical. This is because these lines are not introducing congestion in the transmission lines, instead they are helping to relieve congestion.

The transmission cost per year for generator contribution can also be estimated using the proposed PTDF method and this has also been verified by comparison with Bialek's method as shown in Figure 6.4

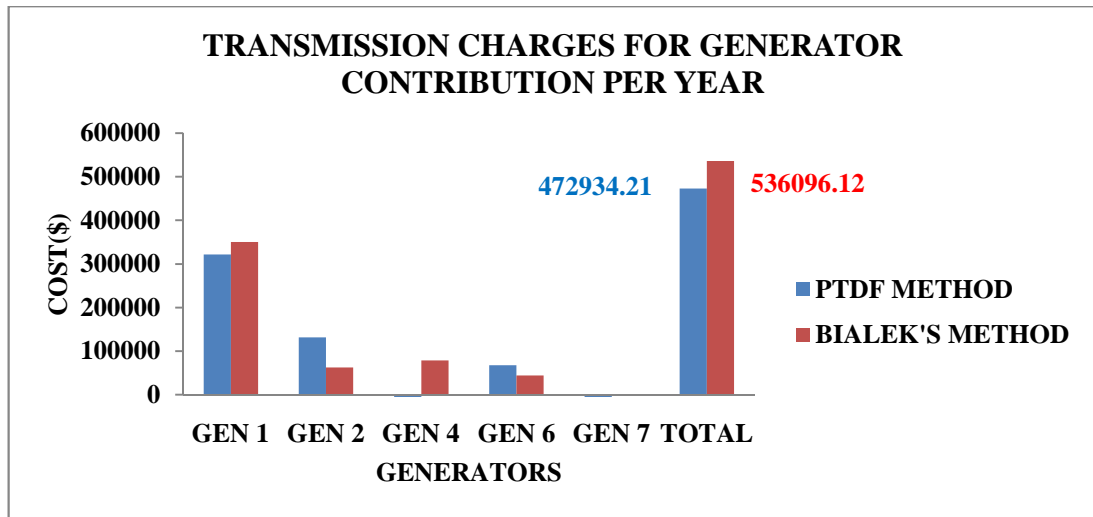


Figure 6.4: Comparison of Transmission Charges for Generator's contribution Per Year of 7-Bus system using BIALEK'S Method and application of PTDF method

As seen from the Bar Chart in Figure 6.4 it is acknowledged that there are some variations between the transmission charges produced by the two methods. This is because the proposed application of PTDF method takes into account all the positive and negative contributions of the generators, but Bialek's method considers only positive contributions and other contributions are neglected. And this can also be seen in the previous tables and figures shown for the load and generator contributions. The proposed application of PTDF method also evaluates the negative flow of power in the line flows which are shown in the load contribution for line flow in Table 6.4.

6.4.2 IEEE 30-BUS SYSTEM

An IEEE 30-Bus system is shown in Figure 4.4 of Chapter 4. The system consists of six generators and twenty one loads. The system has 41 transmission lines. Some of the buses have both generators and loads connected. The line data, generator data, load data and line limits are given in Appendix-B.

After running a Newton-Raphson AC Load Flow one Transmission line, Line 16-17, is found to be congested. The generator and load contributions to Power Flow are determined for both unconstrained and constrained cases in a similar way to the case study for the 7-Bus system.

The power flows for the Unconstrained case are given in the Table 4.5 and Table 4.6 of Chapter-4 and for the Constrained case the load flow is provided in Appendix-E (CD enclosed). The Line flow of transmission line 16-17 in the constrained case has changed from 16.96 MW to 15.88 MW after re-dispatch of generation, which is now under the line limit of 16 MW. Complete results for the 30-Bus system can be found in Appendix-E (CD enclosed).

The total generation cost is determined for constrained and unconstrained cases and the constraint is taken as the Line limits.

The PTDF has been calculated using Power flow by programming it in Matlab and the results are provided in Appendix-E (CD enclosed). From the obtained PTDF, other distribution factors like GGDF and GLDF are also determined. They are calculated using Equations 6.16, 6.17, 6.18, 6.19, 6.20 and 6.21, which are also provided in Appendix-E (CD enclosed).

Using distribution factors obtained from PTDF, load and generation contribution on line flow has been determined which are given in the form of bar charts in Figure 6.5 and Figure 6.6. The tables for the same are provided in Appendix-E (CD enclosed). Also the generator and load contributions to line flow and each other are also determined using Bialek's method, which are shown in bar chart form in Figure 6.7, Figure 6.8, Figure 6.9 and Figure 6.10. The tables for the same are provided in Appendix-E (CD enclosed).

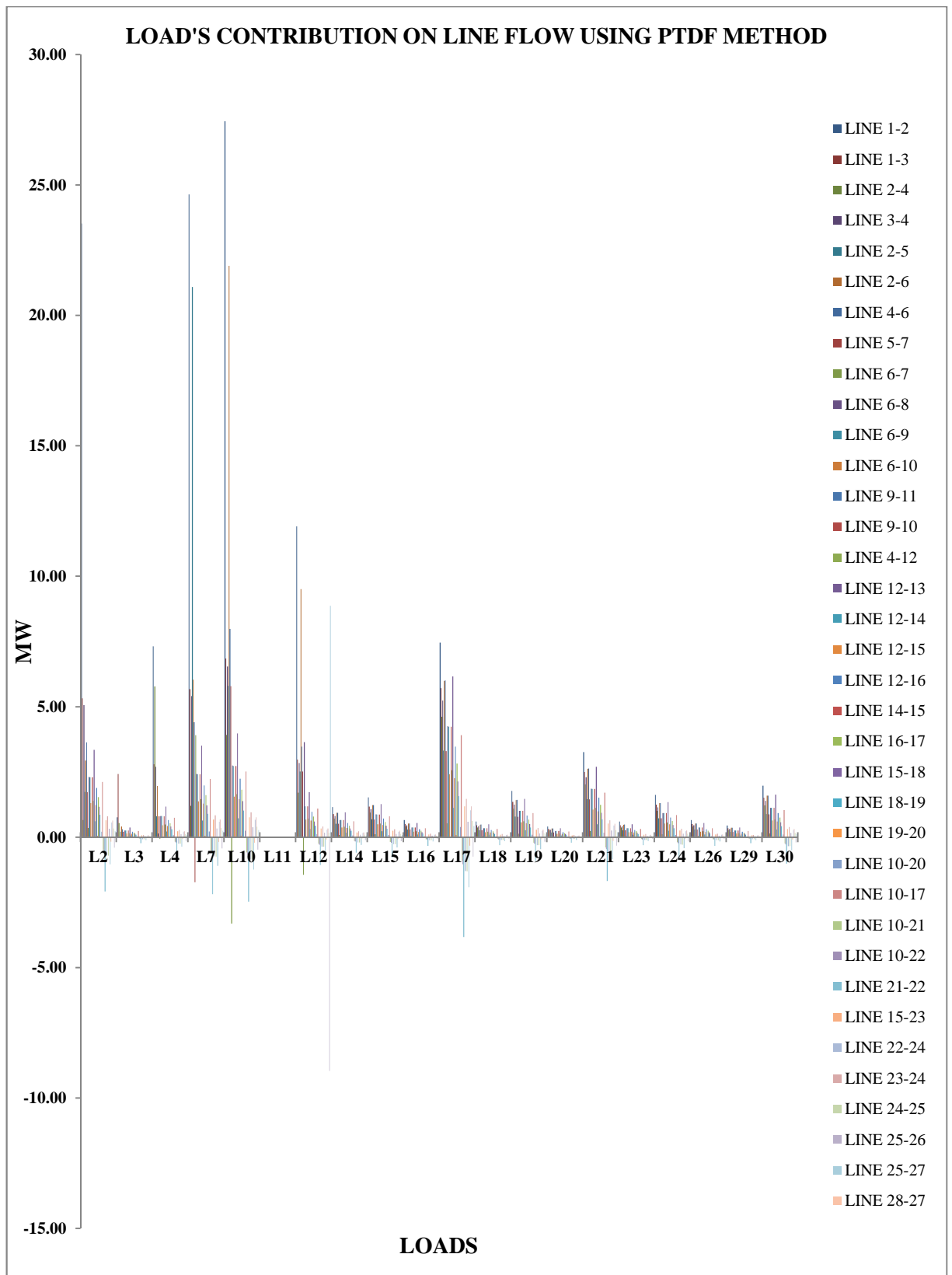


Figure 6.5: Bar Chart Load Contribution on Line Flow for IEEE 30-Bus system using application of PTDF Method

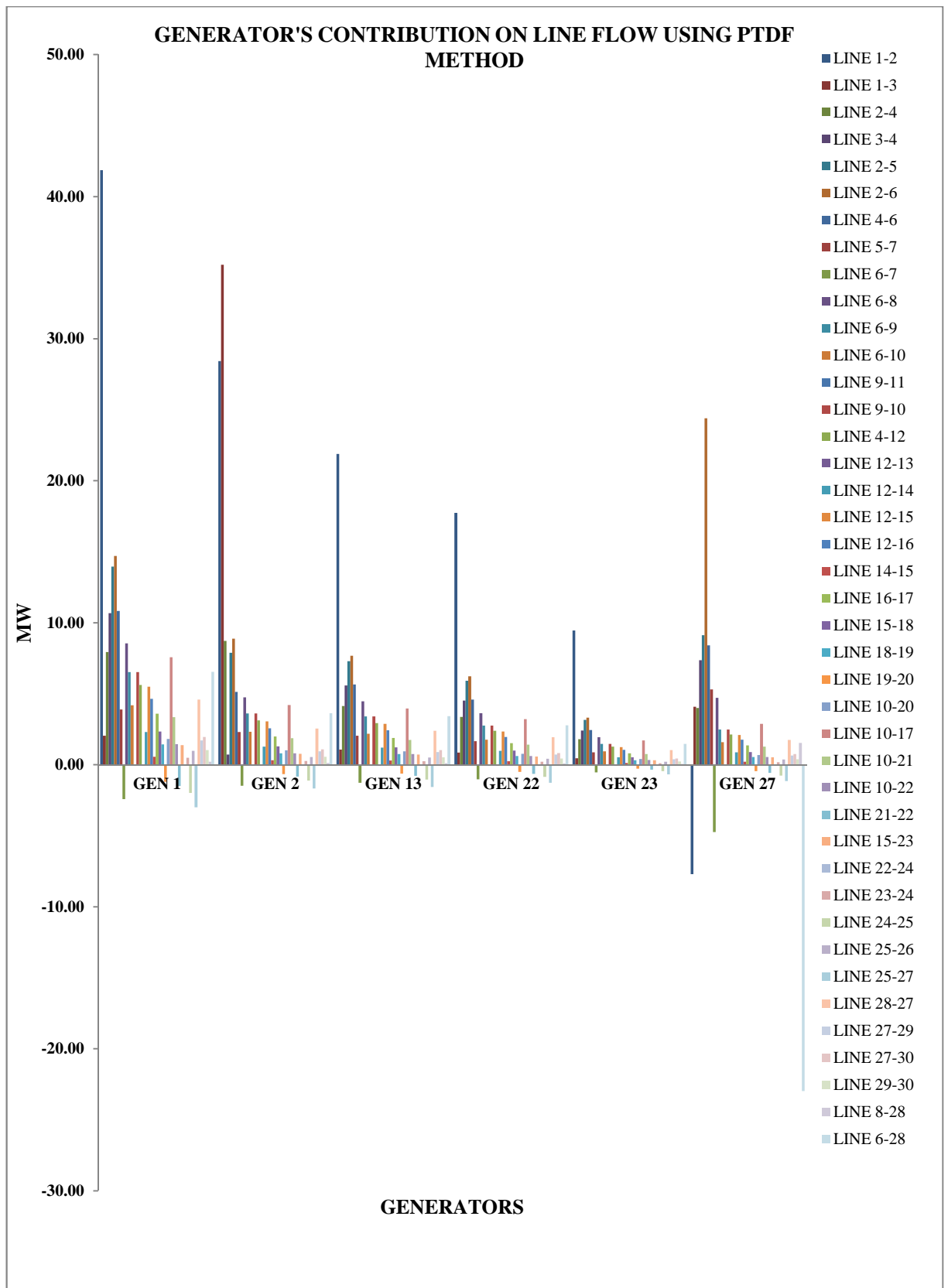


Figure 6.6: Bar Chart Generator's Contribution on Line Flow for IEEE 30-Bus system using application of PTDF Method

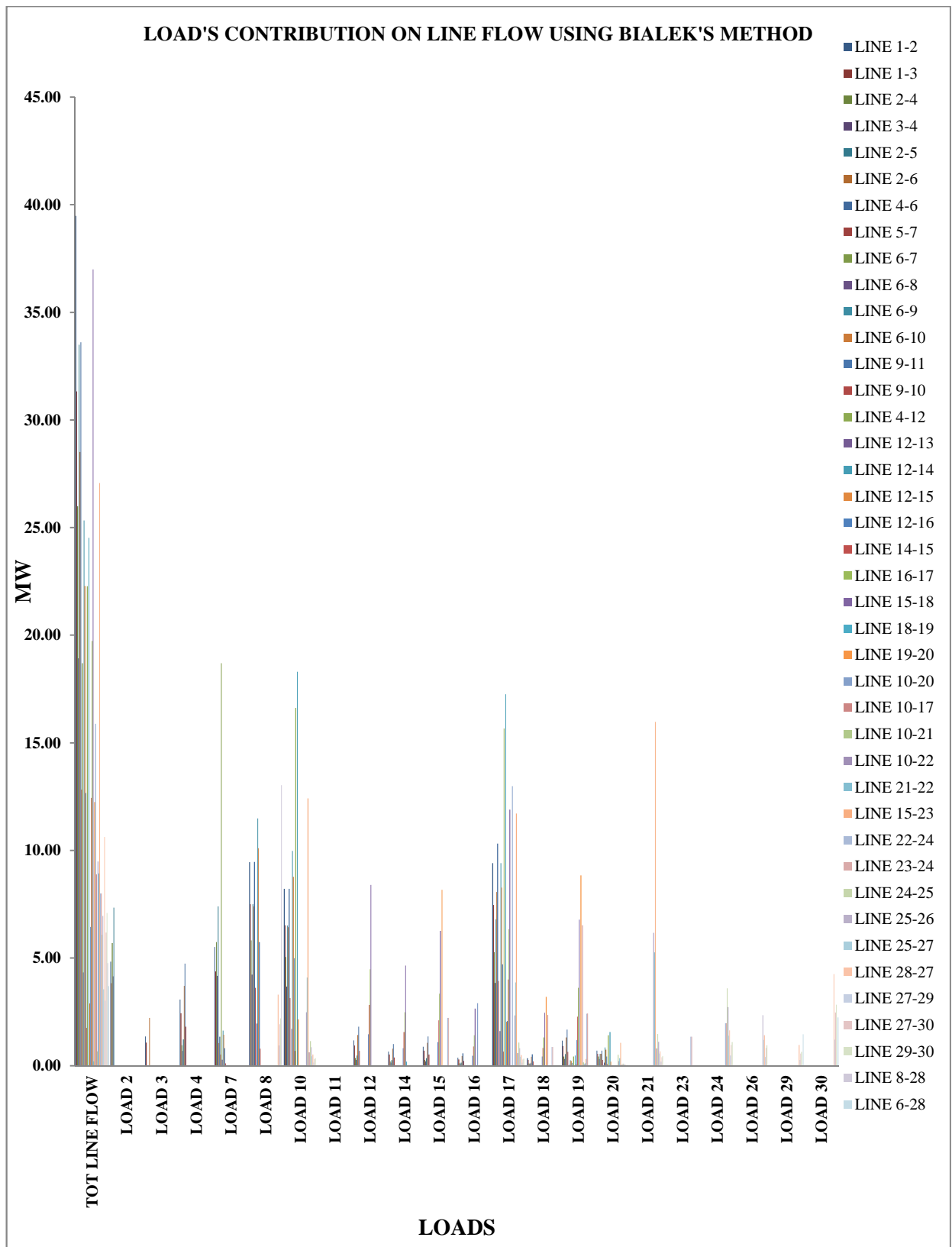


Figure 6.7: Load Contribution on Line Flow for IEEE 30-Bus system using BIALEK'S Method

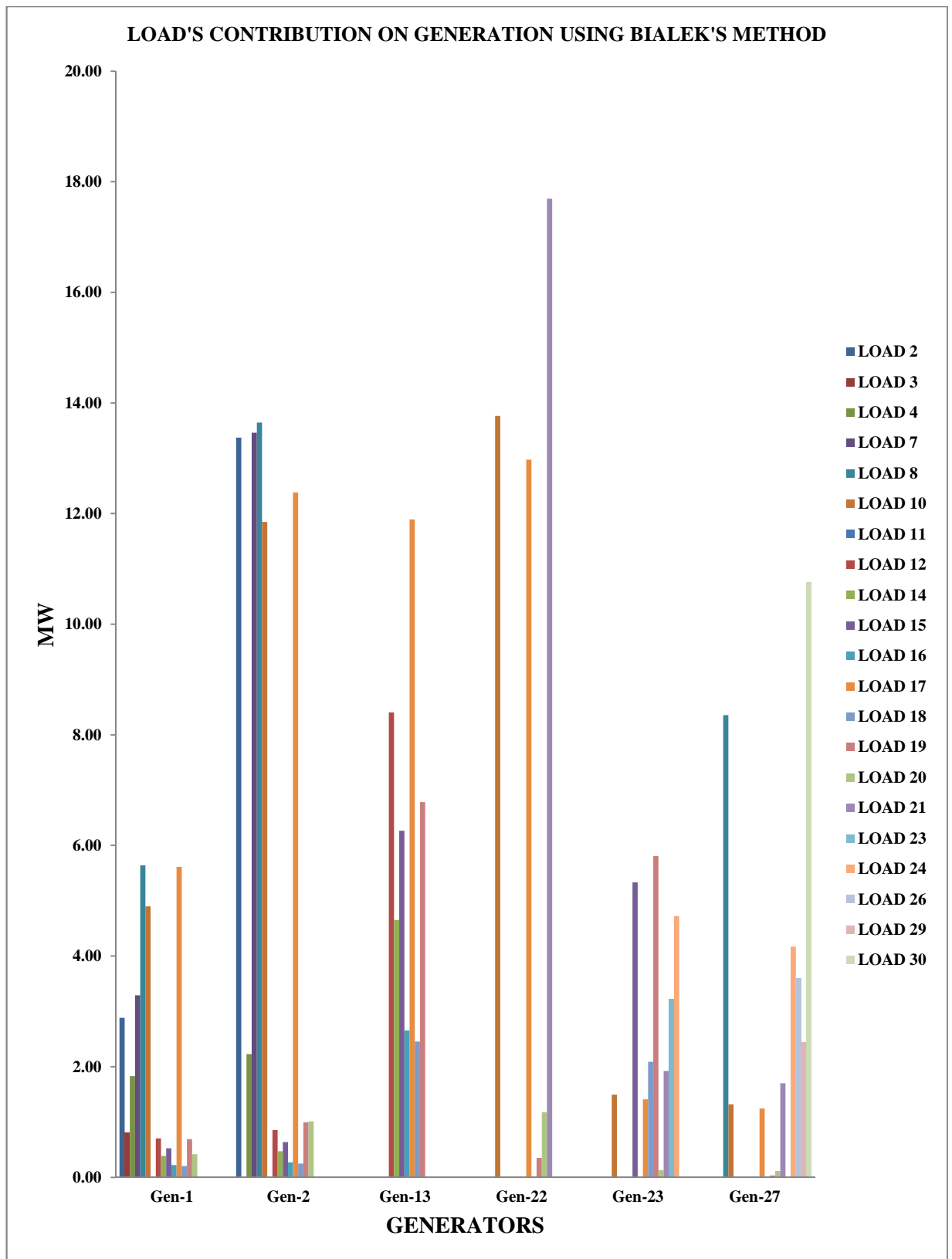


Figure 6.8: Load Contribution on Generators for IEEE 30-Bus system using BIALEK'S Method

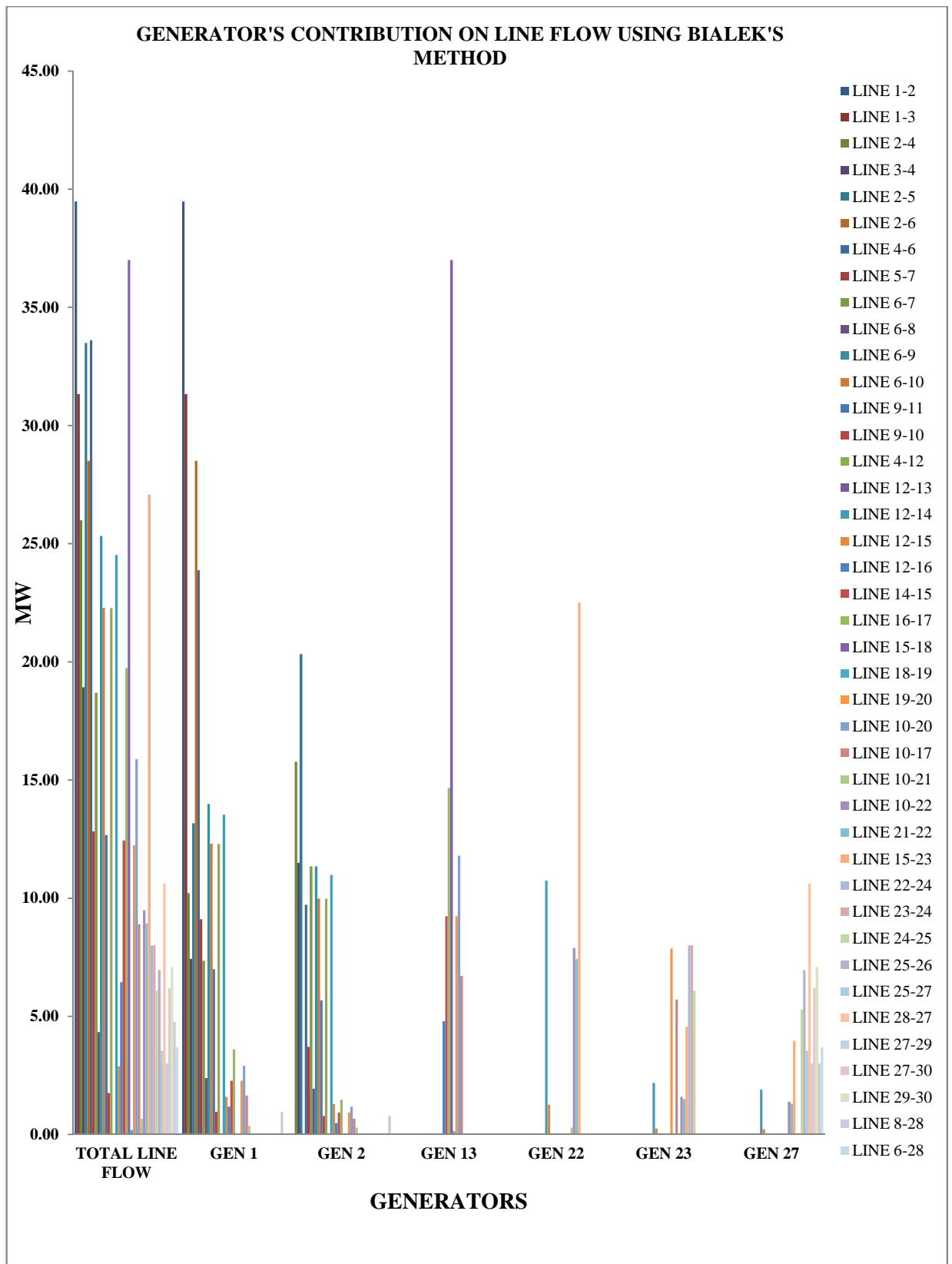


Figure 6.9: Generator Contribution on Line Flow for IEEE 30-Bus system using BIALEK'S Method

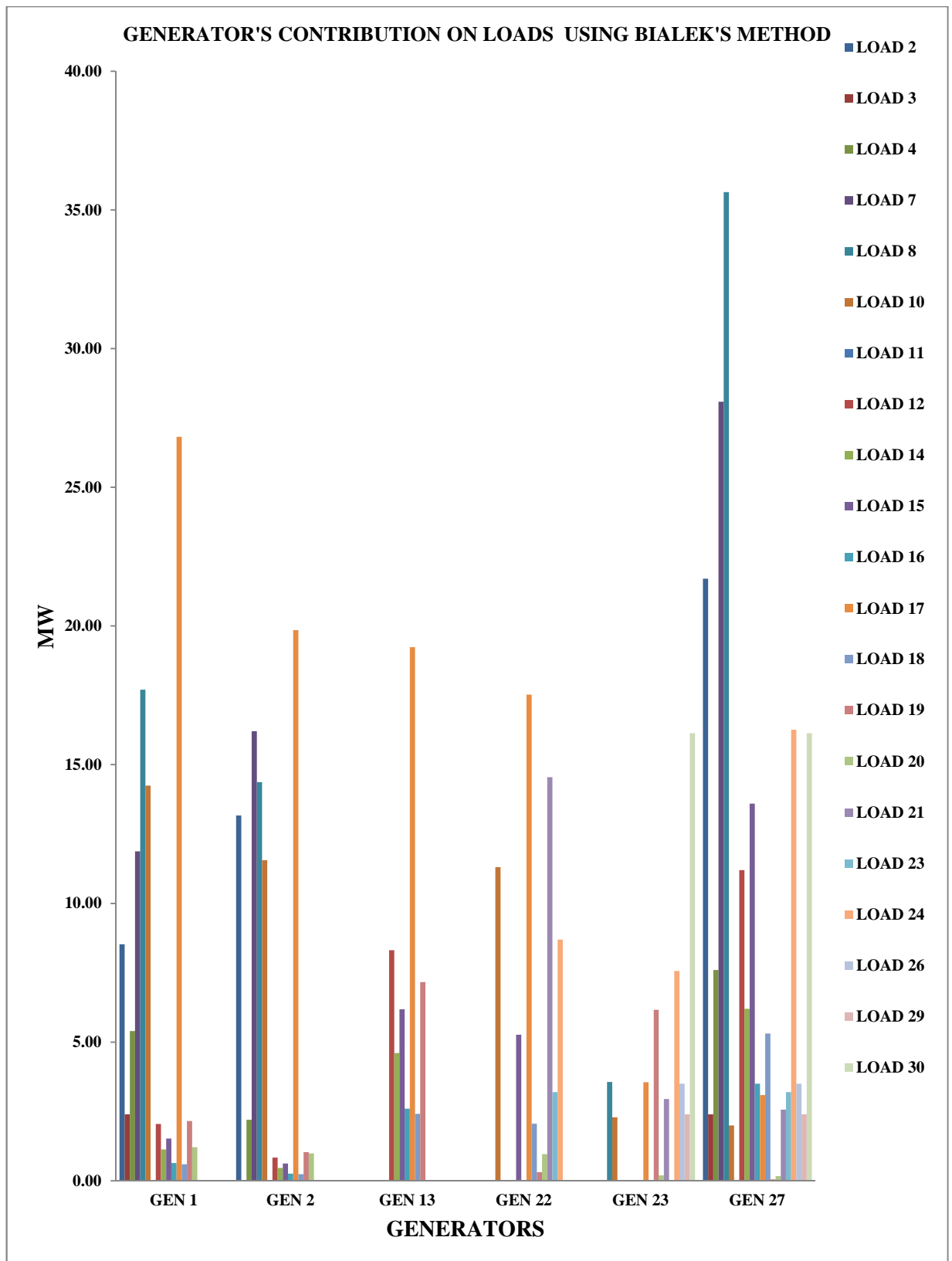


Figure 6.10: Generator Contribution on Loads for IEEE 30-Bus system using BIALEK'S Method

The calculated Relief Cost for the congested line is as follows:

$$RC_{16-17} = -8.74 \text{ (\$/Hr)}$$

So the calculated constrained allocation cost which is the distribution of TCC among each lines using Equation 6.6 is:

$$TC_{16-17} = TCC = -16.8 \text{ (\$/Hr)}$$

This can be verified from Table 6.12. These constraint costs are divided among all the Loads responsible for congestion using the proposed application of PTDF method by calculating the Load Contribution on line Flow.

Table 6.12: Total Congestion Cost for IEEE 30-Bus system using application of PTDF Method

TOTAL CONGESTION COST USING PTDF METHOD		
LOAD	C*LOAD (LINE 16-17)	TCC (\\$/Hr)
2	0.00	0.00
3	0.00	0.00
4	0.00	0.00
7	0.00	0.00
8	0.00	0.00
10	0.00	0.00
11	0.00	0.00
12	0.00	0.00
14	0.00	0.00
15	0.00	0.00
16	-2.90	-3.04
17	-12.99	-13.64
18	0.00	0.00
19	0.00	0.00
20	0.00	0.00
21	0.00	0.00
23	0.00	0.00
24	0.00	0.00
26	0.00	0.00
29	0.00	0.00
30	0.00	0.00
TOTAL	-15.88	-16.68

It can be seen from Table 6.13 using Bialek's Method that generation at Bus 1 is reduced and the generation at Bus 21 has increased during re-dispatch to relieve the congestion in the transmission lines. The increase in generation cost, which is also termed as the Total Congestion Cost (TCC) is given in Table 6.13 for complete analysis. The TCC for the IEEE 30-Bus system is found to be -15.80 (\$/Hr).

Table 6.13: Total Congestion Cost for IEEE 30-Bus system using BIALEK'S Method

TOTAL CONGESTION COST USING BIALEK'S METHOD					
GEN	GEN(MW)		COST(\$/Hr)		TCC(\$/Hr) CASE2-CASE1
	CASE 1	CASE 2	CASE 1	CASE 2	
Gen-1	79.72	70.80	1322.91	1162.25	-160.65
Gen-2	60.97	60.97	964.36	964.36	0.00
Gen-13	37.00	37.00	626.23	626.23	0.00
Gen-22	21.59	30.00	331.39	476.25	144.86
Gen-23	19.20	19.20	316.42	316.42	0.00
Gen-27	26.91	26.91	416.39	416.39	0.00
TOTAL			3977.69	3961.89	-15.80

By comparing the results obtained using the proposed application of PTDF method in Table 6.12 and Bialek's method in Table 6.13 it is found that both methods result in a similar cost for congestion i.e. according to Bialek's method the congestion cost is -15.8 (\$/Hr) and from the proposed application of PTDF method it is -16.68 (\$/Hr). The congestion cost calculated has a negative value because after re-dispatching the generators the total cost of generation is reduced and hence this is reflected in the congestion cost.

The transmission cost for generator contribution per Year can also be estimated using the proposed application of PTDF method and this has also been verified by comparing the results with Bialek's method shown in Figure 6.11.

As seen from the Bar Chart in Figure 6.11, there is some variation of the transmission charges calculated by each method. This is because the proposed application of PTDF method takes into account all the positive and negative

contributions of generation but Bialek's method considers only the positive contribution and other contributions are neglected. And this can also be seen in the previous tables and figures shown for the load and generator contribution. The proposed application of PTDF method also evaluates the negative flow of power in the line flows which are shown in the load contribution for line flow in Figure 6.5.

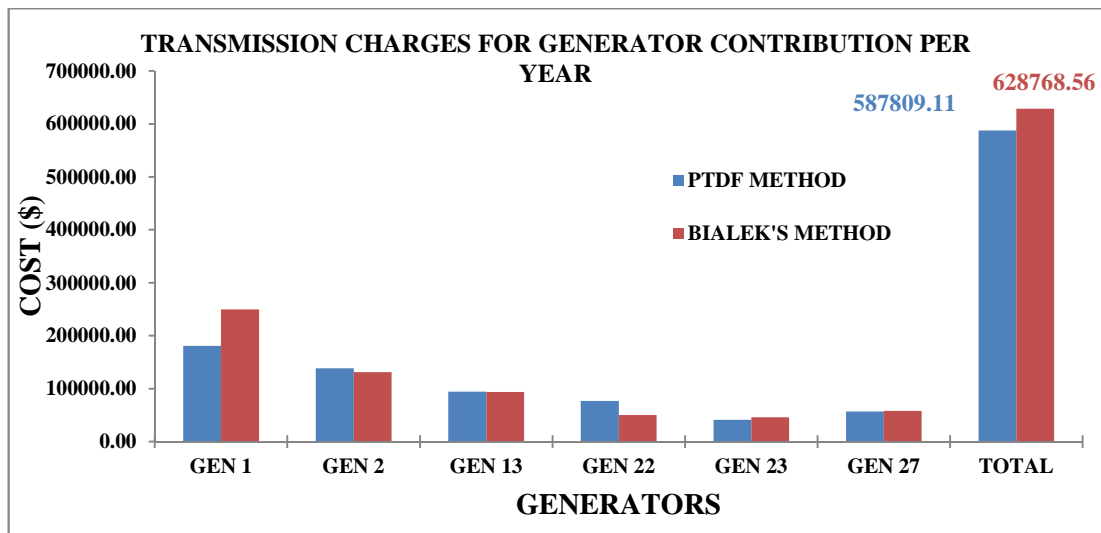


Figure 6.11: Comparison of Transmission Charges for Generator's contribution Per Year of IEEE 30-Bus system using BIALEK'S Method and application of PTDF method

6.4.3 INDIAN UTILITY 146-BUS SYSTEM

An Indian Utility 146-Bus system is shown in Figure 4.5 of Chapter 4. The system consists of 24 generators and 100 loads. The system has 169 transmission lines. Some of the buses are have both generators and loads connected. The line data, generator data, load data and line limits are given in Appendix-C.

After running a Newton-Raphson AC Load Flow two Transmission lines, Line 28-27 and line 28-34 are found to be congested. . The generator and load contributions to Power Flow are determined for both unconstrained and constrained cases in a similar way to the case study for the 7-Bus system.

The power flows for the Unconstrained case are given in the Table C4 and Table C5 of Appendix-C and for the Constrained case the power flow is provided in Appendix-E (CD enclosed). The Line flow of transmission line 28-27 in the constrained case has changed from -343.15 MW to -201.53 MW and the line flow for line 28-34 in the constrained case has changed from -974.68 MW to -897.65 MW after re-dispatch of generators and are now under the line limit of 300 MW and 900 MW respectively. Complete results from the 146-Bus system can be found in Appendix-E (CD enclosed).

The total generation cost is determined for constrained and unconstrained cases and the constraint is taken as the Line limits.

It can be seen from the Table 6.15, using Bialek's Method, that generation at buses 28, 29, 34, 36, 37, 58, 61, 62 & 88 is reduced and generation at buses 1, 38, 49, 63, 75, 79 & 83 has increased during re-dispatch in order to relieve the congestion on the transmission lines. The increase in generation cost, which is also termed the Total Congestion Cost (TCC), is given in Table 6.15. The TCC for the Indian Utility 146-Bus system is found to be -2098.43 (\$/Hr).

The PTDF has been calculated using Power flow by programming in Matlab and the results are provided in Appendix-E (CD enclosed). From the obtained PTDF, other distribution factors like GGDF and GLDF are also determined. They are calculated using Equations 6.16, 6.17, 6.18, 6.19, 6.20 and 6.21, which are also provided in Appendix-E (CD enclosed).

Using the distribution factors obtained from PTDF, load and generation contribution on line flow has been determined which are provided in Appendix-E (CD enclosed).

Table 6.14: Total Congestion Cost for Indian Utility 146-Bus using application of PTDF Method

TOTAL CONGESTION COST USING PTDF METHOD					
LOAD	LINE 28-27	TC-1 (\$/Hr)	LINE 28-34	TC-2 (\$/Hr)	TCC (\$/Hr)
163	-75.08	-78.83	-75.08	-78.83	-157.66
86	-39.61	-41.59	-39.61	-41.59	-83.18
40	-18.42	-19.35	-18.42	-19.35	-38.69
67	-30.86	-32.40	-30.86	-32.40	-64.81
1	-0.46	-0.48	-0.46	-0.48	-0.97
149	-68.63	-72.06	-68.63	-72.06	-144.12
10	-4.61	-4.84	-4.61	-4.84	-9.67
44	-20.27	-21.28	-20.27	-21.28	-42.56
130	-59.88	-62.87	-59.88	-62.87	-125.74
121	-55.73	-58.52	-55.73	-58.52	-117.04
109	-50.21	-52.72	-50.21	-52.72	-105.43
109	-50.21	-52.72	-50.21	-52.72	-105.43
70	-32.24	-33.85	-32.24	-33.85	-67.71
125	-57.57	-60.45	-57.57	-60.45	-120.91
40	-18.42	-19.35	-18.42	-19.35	-38.69
161	-74.16	-77.86	-74.16	-77.86	-155.73
132	-60.80	-63.84	-60.80	-63.84	-127.68
95	-43.76	-45.94	-43.76	-45.94	-91.89
74	-34.08	-35.79	-34.08	-35.79	-71.58
81	-37.31	-39.17	-37.31	-39.17	-78.35
22	-10.13	-10.64	-10.13	-10.64	-21.28
17	-7.83	-8.22	-7.83	-8.22	-16.44
10	-4.61	-4.84	-4.61	-4.84	-9.67
42	-19.35	-20.31	-19.35	-20.31	-40.62
60	-27.64	-29.02	-27.64	-29.02	-58.04
46	24.81	26.05	-21.19	-22.25	3.81
94	-43.30	-45.46	-43.30	-45.46	-90.92
48	25.89	27.19	-22.11	-23.21	3.97
248	-114.23	-119.94	-114.23	-119.94	-239.88
130	-59.88	-62.87	-59.88	-62.87	-125.74
66	-30.40	-31.92	-30.40	-31.92	-63.84
124	-57.11	-59.97	-57.11	-59.97	-119.94
93	-42.84	-44.98	50.16	52.67	7.70
60	-27.64	-29.02	32.36	33.98	4.96
210	-96.73	-101.56	113.27	118.94	17.38
149	-68.63	-72.06	80.37	84.39	12.33
111	-51.13	-53.68	59.87	62.87	9.18
127	-58.50	-61.42	68.50	71.93	10.51
92	-42.37	-44.49	49.63	52.11	7.61
20	-9.21	-9.67	10.79	11.33	1.65
83	-38.23	-40.14	44.77	47.01	6.87
25	-11.51	-12.09	13.49	14.16	2.07
77	-35.47	-37.24	41.53	43.61	6.37
30	-13.82	-14.51	16.18	16.99	2.48
5	-2.30	-2.42	2.70	2.83	0.41
145	-66.79	-70.13	78.21	82.12	12.00
88	-40.53	-42.56	47.47	49.84	7.28
1	-1786.16	-1875.46	-516.16	-541.96	-2417.43

Table 6.15: Total Congestion Cost for Indian Utility 146-Bus system using BIALEK'S Method

TOTAL CONGESTION COST USING BIALEK'S METHOD					
GEN No.	GEN(MW)		COST(\$/Hr)		TCC(\$/Hr) CASE2-CASE1
	CASE 1	CASE 2	CASE 1	CASE 2	
GEN 1	311.65	330.35	3231.48	3421.26	189.77
GEN 28	11.53	11.30	881.20	2797.71	1916.51
GEN 29	13.20	12.36	4995.82	3398.98	-1596.84
GEN 34	11.67	11.61	1928.08	1163.51	-764.57
GEN 35	0.22	0.22	919.57	919.57	0.00
GEN 36	47.85	46.17	1790.74	1790.74	0.00
GEN 37	9.11	8.37	1427.32	1427.32	0.00
GEN 38	7.38	7.39	937.34	937.34	0.00
GEN 39	-0.44	-0.44	941.28	941.28	0.00
GEN 44	-4.87	-4.93	941.11	941.11	0.00
GEN 47	-0.10	-0.10	2828.43	985.13	-1843.30
GEN 49	38.44	38.53	3323.98	3323.98	0.00
GEN 58	59.80	58.51	1635.58	1635.58	0.00
GEN 60	-0.34	-0.33	968.24	968.24	0.00
GEN 61	21.92	21.91	953.91	953.91	0.00
GEN 62	52.30	51.12	944.70	944.70	0.00
GEN 63	17.93	17.97	1718.29	1718.29	0.00
GEN 75	43.43	43.55	1686.59	1686.59	0.00
GEN 79	4.90	4.92	1020.30	1020.30	0.00
GEN 80	-8.54	-8.54	953.65	953.65	0.00
GEN 81	-8.73	-8.73	6779.15	6779.15	0.00
GEN 83	96.49	96.62	2097.24	2097.24	0.00
GEN 88	7.24	5.83	942.86	942.86	0.00
GEN 89	1.87	1.74	941.81	941.81	0.00
TOTAL			44788.68	42690.24	-2098.43

Also the generator and load contributions to line flow and each other are also determined using Bialek's method which provided in Appendix-E (CD enclosed).

The calculated Relief cost for the congested lines is as follows:

$$RC_{27-28} = -9.5 \text{ ($/Hr)}, RC_{28-34} = -8.8 \text{ ($/Hr)}$$

So the calculated constrained allocation cost which is the distribution of TCC among each lines using Equation 6.6 is:

$$TC_{27-28} = -1875.46 \text{ ($/Hr)}, TC_{28-34} = -541.96 \text{ ($/Hr)}$$

This can be verified from Table 6.14. These constraint costs are divided among all the Loads responsible for congestion using the proposed application of PTDF method by calculating the Load Contribution on line Flow.

By comparing the results obtained using the proposed application of PTDF method in Table 6.14 and Bialek's method in Table 6.15 it is found that both methods result in a similar cost for congestion i.e. according to Bialek's method the congestion cost is -2098.43 (\$/Hr) and from the proposed application of PTDF method it is -2417.61 (\$/Hr). The congestion cost calculated has a negative value because after re-dispatching the generators the total cost of generation is reduced and hence this is reflected in the congestion cost.

The transmission cost for generator contribution per Year can also be estimated using the proposed application of PTDF method and this has also been verified by comparing the results with Bialek's method shown in Figure 6.12

As seen from the Bar Chart in Figure 6.12 there is some variations of transmission charges calculated by each method. This is because proposed application of PTDF method takes into account for all the positive and negative contributions of generator but Bialek's method considers only positive contribution and other contributions are

neglected. This can also be seen in the tables and figures provided in Appendix-E (CD enclosed). The proposed application of PTDF method also evaluates the negative flow of power in the lines, which are shown in Load contributions using the application of PTDF method in Appendix-E (CD enclosed).

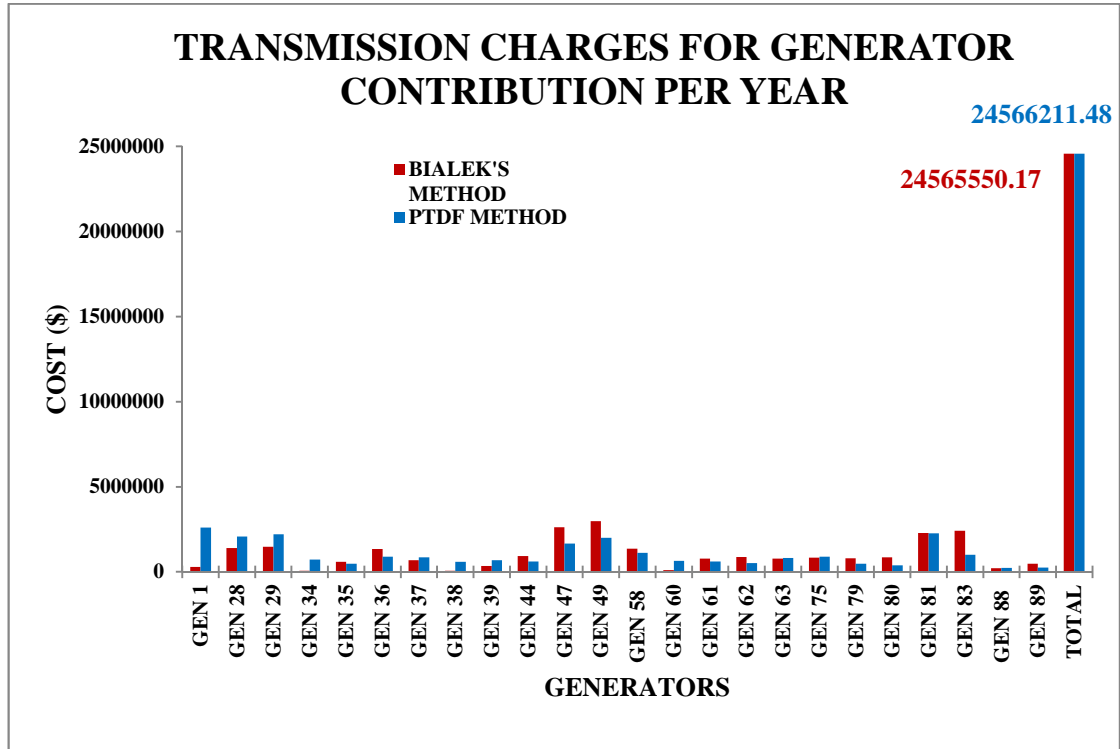


Figure 6.12: Comparison of Transmission Charges for Generator's contribution per Year of Indian Utility 146-Bus system using BIALEK'S Method and application of PTDF method

6.5 SUMMARY

The purpose of performing Congestion studies is to estimate the Congestion cost for the three systems, 7-Bus, IEEE 30-Bus and Indian Utility 146-Bus, using the proposed application of PTDF method and Bialek's method then to compare the results and check their accuracy. The evaluated congestion cost for the 7- Bus system using Bialek's method is 200.94 \$/hr and using the proposed PTDF method its value is 206 \$/hr, which are nearly the same. For IEEE 30-Bus system the congestion cost

using Bialek's method is -15.8 \$/hr and using the proposed PTDF method it is -16.68 \$/hr, which are also approximately the same. Similarly for Indian utility 146-Bus system the congestion cost using Bialek's method is -2098.43 \$/hr and using the proposed PTDF method it is -2417.43 \$/hr. Here we can see the congestion cost using proposed PTDF method is slightly greater than Bialek's method. The Values of congestion cost for IEEE 30-Bus system and Indian Utility 146-Bus system are negative because after applying the line limits and re-dispatching the generators the cost of generation is less than the unconstrained case. So the congestion cost is actually a smaller cost for generation of the same energy. That is why the congestion cost values are negative.

To determine the congestion cost a proposed PTDF method is used which uses other distribution factors to calculate the generator and load contribution on line flow; similarly Bialek's method is used to determine the same. The evaluated load and generators' contribution using both the methods are used to further determine the Transmission Costing. The transmission cost using proposed PTDF method is 2804.36 \$/hr and using Bialek's method is 2804.29 \$/hr, which are almost the same. By this we can conclude that proposed PTDF method used in the DMF for ROTC can be used for determining the congestion cost and also for transmission costing. Finally as stated in the previous sections we have presented summary results and relevant analysis in these sections, with the detailed results and the MATLAB program codes for the studies and simulations conducted in the relevant Appendices due to their large volume.

CHAPTER - 7

RELIABILITY FRAMEWORK A META-ANALYSIS FOR EVALUATING VALUE OF RELIABILITY BENEFITS

7.1 INTRODUCTION

Reliability is one of the fundamental driving factors for transmission expansion. Reliability violation occurs when there is enough capacity to serve load system-wide, but load growth in a particular location on the system is such that the infrastructure is inadequate and not able to avoid an overload at that location. In this case, a transmission upgrade would be required to ensure that the load could be reliably served. As such, reliability is a benefit that is enjoyed by load in a constrained location which allows firm load to be served at all times, and enjoyed by others on the system whose risk of cascading failures is significantly reduced. In addition to reliability maintenance and improvements identified in transmission planning processes, it has also been argued that transmission expansion can guard against and/or mitigate extreme reliability events that involve multiple contingencies occurring simultaneously. One estimate of the avoided cost of such a rare occurrence, such as the 2003 Northeast blackout, is \$5 billion to \$10 billion.

In today's scenario everybody wants to have continuous electrical supply when required but it is not possible technically and economically to organize, develop and operate an Electric power system with 100% probability of success. The aim of the Electric power system is to provide a fairly economical and suitable level of continuous good quality power supply. The quality of supply is calculated in terms of reasonable values of voltage and frequency of supply. The reliability of a system, to

provide an uninterrupted power supply is evaluated in terms of its adequacy and security (Goel, Billinton 1991).

There is always a question before electrical system planners about the sufficient level of reliability required for a stable and economical operation of the electric system. Based on previous experience the levels of reliability cannot be maintained now, as the options and customers are frequently changing, so the electrical industries are looking towards various ways of benefiting customers by providing reliable and economic power supply. But still the same barrier is there to evaluate the level and worth of complete system reliability.

Most of the methods existing for reliability assessment is under the system adequacy domain. For total reliability assessment of the electrical power system the system will be divided into three categories depending upon their mode of function i.e. HL-I, HL-II and HL-III. The indices calculated under each level are different in terms of their importance and application (Billinton, Oteng-Adjei 1991).

Good power system operation requires that there should be no “Reliability” violations (needs to shed load, have cascading outages, or other unacceptable conditions) for either the current condition or in the event of statistically likely contingencies:

Reliability basically requires no transmission line/transformer limit violations and that bus voltages should be within acceptable limits (perhaps 0.95 to 1.08)

According to (Baldick, Bushnell et al. 2011) the methods used for scheduling of generating units, congestion and pricing greatly affect the overall functioning i.e. efficiency and reliability of the system.

7.2 PURPOSE AND IMPORTANCE OF RELIABILITY WORTH STUDIES

Supplying reliable and cost effective electric power to the consumer is the main motive of all the power utilities but the price depends upon the level of reliability standards, which increases with higher reliability and decreases with lower reliability. Electrical system reliability will decrease if the electrical supply is close to the components rated capacity; in that case, the electricity price will probably be lower. Some systems utilise their network below its rated capacity which makes reliability much higher but the price of supplying electricity will rise. So what is required is a balance between economical and technical issues where network overall usage can come to an optimum level and price will be reasonable (Reliability Outage Cost Study).

Shown below is the relationship between cost and reliability in Figure 7.1, from which it can be concluded that the optimum level of reliability can be achieved at the balance point between the cost of service and the price charged to the consumers. So there is a need to evaluate the supply cost at different levels of reliability.

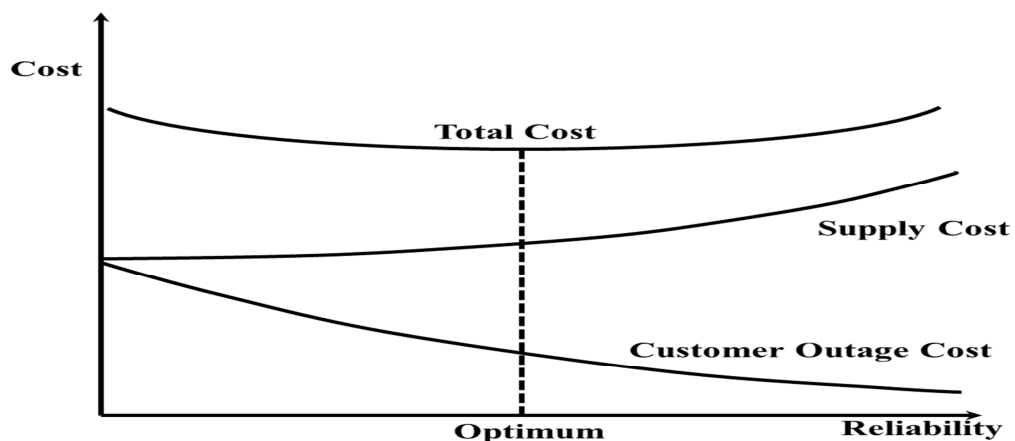


Figure 7.1: Costs and Reliability Curve

Source: (Manikya Rao.J, Prasad.P.V.N. et al. AUGUST 2010)

The cost at different levels of reliability can be evaluated by using reliability indices such as IEAR and ECOST which can be evaluated using the operating statistics of the installed system components. From the analysis it can be concluded that to calculate the outage cost the customer damage cost has to be evaluated, and then the outage cost will be used to calculate the reliability for system planning and operation. Due to outage in the electrical network the damage can be both direct and indirect to the customers. Direct damage can be loss of production, inconvenience and damage to life and property etc. and indirect damage can be crime, cancelation of orders due to manufacturing delays etc. Both direct and indirect damage have to be calculated to get the approximate outage cost (, Reliability Outage Cost Study).

7.3 INDICES TO CALCULATE FOR DETERMINATION OF RELIABILITY WORTH

As we know, it is possible to calculate the direct damage cost but calculating indirect cost is not possible as it varies between different modes of usage. In order to evaluate the outage cost we can classify them according to type of customers, quantity of power used, interrupted activities and duration of power outages.

The outage cost estimation is carried out by face to face or online services surveys. From the data collected we can develop a model for customer outage cost to calculate the damage cost and the reliability indices which will further be used to evaluate the worth of reliability in an electrical system.

In order to achieve the levels of reliability and investment cost, Reliability standards for supplying electrical services has to be evaluated in terms of capital cost and to do

so; Expected Interruption Cost (EIC) has to be calculated. To calculate the worth of reliability the Customer Interruption Cost (CIC) index is calculated and used.

SCDF (Sector Customer Damage Function): The data collected from the customer survey is classified and arranged according to class, type or sectors of customers such as residential, commercial, industrial, government etc.

A customer survey is conducted and the data collected is formulated to find the SCDF which is the interruption cost in the sectors as a function of duration of outage.

CCDF (Composite Customer Damage Function): The data from SCDF is used and the damage function is created for different categories of customers and that forms the CCDF. It is the sum of ICDF (Individual Sector Customer Damage Function) in the categorised customers.

At any load point the customer outage cost due to any system failure is the cost of all the different types of consumers which are linked to that point of the system and this collective cost is called CCDF.

“The CCDF is an estimate of the costs associated with power supply interruptions as a function of the interruption duration for the customer mix in the particular service area” (Billinton, Oteng-Adjei 1991).

CDF (Customer Damage Function): Is the transformed and processed data from the customer surveys.

The different types of customers have varying costs of interruption due to a specific outage in terms of duration. So to evaluate this, a weighted average is calculated considering annual peak demand and the consumption of energy by specific customers or group of customers. If the duration is short i.e. 1 ½ hour, then annual

peak demand distribution is used as a weighing factor and if it is more than that then energy consumption distribution (\$/KW) is used.

Some of the techniques evolved till now in order to evaluate the customer interruption cost and their application are discussed below.

1. The reliability cost is designed on the basis of the electricity tariff; minimum estimation is carried out on the basis of the tariff structure and the maximum is designed according to the cost of standby plant.
2. Previous production value is determined by taking the ratio of annual gross national production to the total energy consumption. By using this value, the cost of reliable service is determined.
3. The value of previous free time of customer compared to their wages is used for the customer damage cost evaluation.
4. The hourly depreciation cost of all the available electrical home appliances which are not used due to the interruptions are used for the determination of residential customer damage function.

Many researchers proposed reliability evaluation by considering the customer's satisfaction and others by taking the point of view of the service provider. But as it is known that every electrical utility wants their customers to be satisfied in terms of quality and cost of services it is imperative to conduct the evaluation considering both the demand and supply side.

Presently it is important to evaluate the system reliability without considering the worst case criterion due to the increased cost of supply. The evaluation should be performed on the basis of the occurrence of the event and also predicting the extreme effect of it on the system operation. This type of evaluation will render the option to

the system planners and operators to provide electrical supply with quality and continuity and within cost limits.

The basic index for evaluation of system adequacy is LOEE, which calculates the energy undelivered due to lack of generation or reserve capacity or failure in transmission network. This index is linked with the cost of outage to the customers, and by using this index IEAR factor is estimated which can be further used for determining the levels of system reliability that can be introduced in the system planning and development.

IEAR calculated overall cost that the customer has to bear for each unit of energy not supplied due to an outage. The overall cost of reliability will be estimated using IEAR along with other adequacy indices.

The evaluated IEAR values can be utilized along with the adequacy indices to calculate the serious effect of interruption on the customers and on the network. A Contingency enumeration method has been used to determine the EENS index, which can be further used along with the customer cost function in order to determine the IEAR values.

IEAR values can be used to estimate the process of optimal load shedding when any load point outage occurs at HL-II level. The IEAR values determined at the customer load point and at the bulk system load point can also be used in calculating customer rates considering reliability.

In order to evaluate IEAR using Monte Carlo simulation the state variables are the specific events and not the expected values as used in frequency and duration method. IEAR gives the value of EENS in monetary terms.

According to the energy method the customer cost of energy not served ‘C’ is directly related to EENS by the system i.e. Customer Cost $C = \text{IEAR} * \text{LOEE}$.

For varying peak load the above expression shows that IEAR values do not change substantially, so for study and modelling purposes fixed IEAR values can be used in the models.

For peak load the sum cost of energy not supplied at each load bus is the cost of energy not supplied for that system at a particular load point.

7.3.1 EXPECTED ENERGY NOT SUPPLIED (EENS)

The EENS for the system is calculated by weighing the system cost of undelivered energy by the probability of having a particular load increased. And the total of all system cost for unserved energy is the annual system cost for the particular load increment.

The EENS equation can be written in the following form,

$$EENS = \sum_{si \in F} p_{si} \cdot (\mu_{si} + \lambda_{si}) \cdot d_{si} \cdot L_{csi} \quad (7.1)$$

Where, $d_{si} = \frac{8760}{\mu_{si} + \lambda_{si}}$ hours, which is the expected duration at system state ‘si’

L_{csi} , is the load curtailment at the load point in system state ‘si’, ‘ p_{si} ’ is the probability of system state ‘si’ and F is the set of system state in which load curtailment occurs (EASSA 2011).

7.3.2 EXPECTED CUSTOMER DAMAGE COST (ECOST)

The ECOST at a specified system service area or at a load bus can be determined by replacing ‘ d_{si} ’ in Equation 7.1 with $c(d_{si})$, where $c(d_{si})$ is the cost of energy not supplied during the load loss event ‘si’ and is measured in \$/KW.

$$ECOST = \sum_{si \in F} p_{si} \cdot (\mu_{si} + \lambda_{si}) \cdot c(d_{si}) \cdot L_{csi} \quad \text{K\$/year} \quad (7.2)$$

7.3.3 INTERRUPTED ENERGY ASSESSMENT RATE (IEAR)

IEAR is the index used for analysing the reliability worth and it is calculated as the ratio of the ECOST and EENS at either the load buses or for the overall system. The equation can be written as,

$$IEAR = \frac{ECOST}{EENS} \text{ (\$/kWh)} \quad (7.3)$$

IEAR is a convenient index, which gives the monetary evaluation of energy deficiencies at the load buses or the overall system considering the customer damage cost.

7.4 CAPACITY OUTAGE PROBABILITY TABLE (COPT)

For the loss of load approach, the generation model representation is known as the Capacity outage probability table. It is a simple array of capacity levels and the associated probabilities of existence (Billinton, Li 1994). If all the units are identical in capacity, a Binomial distribution can be used for forming COPT. A recursive algorithm is used to develop a COPT for generators.

7.5 MONTE CARLO SIMULATION METHOD

The Monte Carlo method is generally used to represent stochastic simulation using random numbers. MC methods are broadly classified into two categories: Non-sequential (random sampling) and sequential (chronological sampling) simulations. In non-sequential sampling the states of the system components are sampled based on their probability distribution. In sequential MC method the artificially generated chronological history of each system component are considered for simulation.

The Sequential MC technique works on time domain. Using this method reliability indices as well as the correlation between other components of the system can be determined. This method has an advantage in its application for any type of electrical

system as it can imitate the stochastic behaviour of system components. The reliability indices evaluated using this method can be realistic by providing uncertainties of the loads. The demerit of this method is that it takes more time to converge than the non-sequential method.

The MC simulation convergence is dependent upon the variance of the reliability indices. It is known statistically that an index with low variance is more accurate compared to one with high variance. In order to reduce the computational time of the sequential MC approach, the Variance Reduction Techniques (VRT) can be used (Billinton, Li 1994).

Some of the Variance reductions Technique are as follows:

1. Simple Sampling
2. Importance Sampling
3. Stratified Sampling
4. Dagger Sampling

7.5.1 SIMPLE SAMPLING

This technique can be used to investigate the advantage of VRT. From one simulation 'j' the estimated expected value can be found using Equation No. 7.4 which is the basic principle of large numbers and is the most important property of the MC method.

$$m_{x,j} = \frac{1}{n} \sum_{i=1}^n x_i \quad (7.4)$$

The expected value of the simulation is evaluated using Equation 7.5.

$$m_x = \frac{1}{sim} \sum_{j=1}^{sim} m_{x,j} \quad (7.5)$$

The expected variance can be calculated using Equation 7.6.

$$\sigma_X^2 = \frac{1}{sim} \sum_{j=1}^{sim} (m_{x,j} - m_x)^2 \quad (7.6)$$

7.5.2 STRATIFIED SAMPLING

This method is applied if the system behaviour in different conditions is known. The samples are generated by dividing the system states in parts to form the stratum (parts) which are the concentrated samples. After that the results of each stratum are weighted together to form an output for the total system. The main disadvantage of this method is the process of defining each state into different stratum.

7.5.3 IMPORTANCE SAMPLING

This is a process of changing the probability density function of sampling in such a manner that the event which contributes most to the results have the greater probability of occurrence. This method is similar to the stratified method in terms of concentrating the samples. The samples are obtained by modifying the random number generation to probability distribution. The over and under- represented part results are weighted to evaluate the complete results as shown in Figure 7.2.

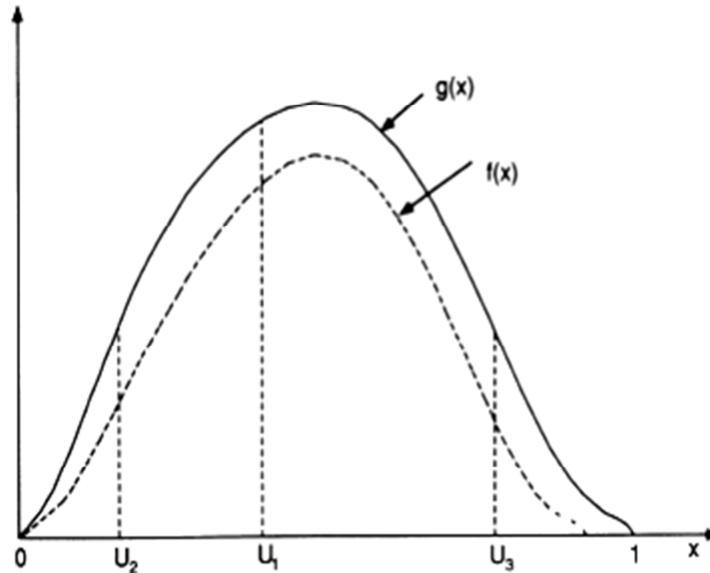


Figure 7.2: Importance Sampling Explanation

Source: (Billinton, Li 1994)

The problem of estimating an adequacy index in reliability evaluation is similar to the problem of evaluating an integral by MC method. The importance sampling is based on the problem of estimating an integral.

The integral between $[0, 1]$ is,

$$I = \int_0^1 g(x) dx \quad (7.7)$$

The integral estimation using the expected value estimation method is,

$$I = E(g(U)) \approx \frac{1}{N} \sum_{i=1}^N g(x_i) \quad (7.8)$$

Where, U is uniformly distributed random numbers between $[0, 1]$.

If the function for the probability density is changed from uniform distribution to $f(x)$, having the same shape as $g(x)$, then the random number with larger contribution in the integral will have greater probability of occurrence.

After multiplying and dividing Equation 7.7 by $f(x)$,

$$I = \int_0^1 \frac{g(x)}{f(x)} f(x) dx \quad (7.9)$$

The new probability density function formed $f(x)$ is the importance sampling density function. The importance sampling method can be applied in power system reliability evaluation to sample loads or hydrological states. As it is little difficult to form a proper importance density function for practical applications, a trial sampling is conducted for an importance sampling density function.

7.5.4 DAGGER SAMPLING

This method can be used for two state variables and events with small probability. System component states can be determined for power system reliability evaluation using this method. In dagger sampling there is a correlation between different

random vectors, and therefore this method has smaller variance than using the direct MC sampling method.

7.6 FLOW CHART FOR IEAR EVALUATION AT 7TH BUS OF 7-BUS SYSTEM

The following Flow Chart in Figure 7.3 explains the process and the proposed MAPA used for achieving ROTC. The MATLAB codes used to obtain the results are provided in Appendix-D.

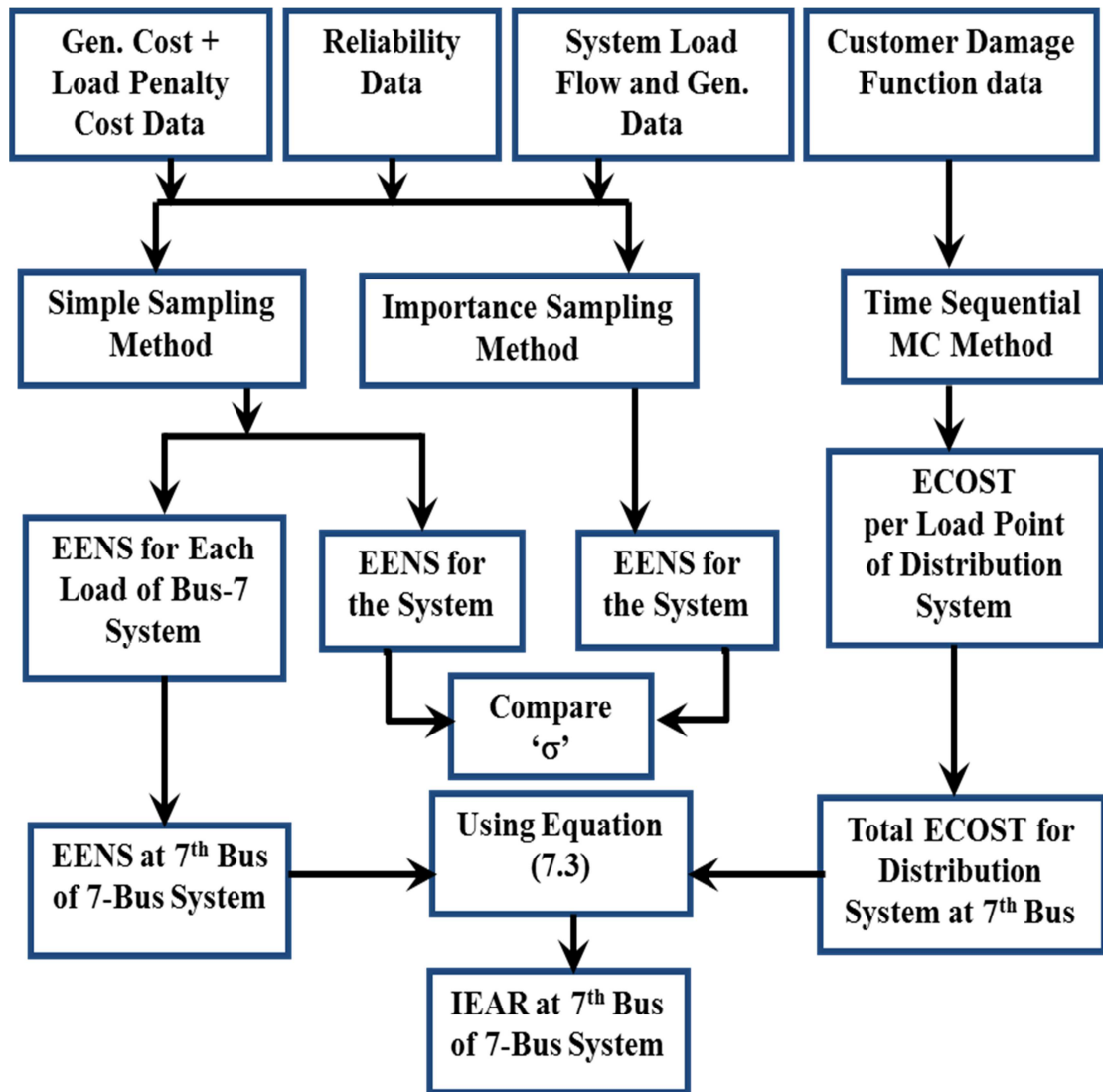


Figure 7.3: Flow Chart for IEAR Evaluation

7.7 MONTE CARLO SIMULATION METHODS APPLIED IN THE RESEARCH FOR ESTIMATING EENS

To determine the worth of Reliability in power system the proposed MAPA has been used. This part of the research utilises Probabilistic methods i.e. Monte Carlo simulation method in which Variance Reduction Techniques such as

- b) Simple Sampling
- c) Importance Sampling and
- d) Time sequential approach were used for estimation of
 - i) EENS
 - ii) ECOST &
 - iii) IEAR index

Simple Sampling and Importance sampling method have been used to determine EENS and also to compare their output accuracy and speed.

The simple and Importance Sampling approach is chosen for estimating the Reliability worth because both the methods can be applied to evaluate the system indices of a composite generation and transmission system. Importance Sampling takes time for simulation but provides accurate results and Simple Sampling also has a variance close to Importance Sampling but takes less time for simulation. To match the balance of speed and accuracy both the methods have been chosen for Reliability worth estimation. The Stratified Sampling can be used when the annual load curve is used to find the unreliability indices. Dagger Sampling is best suited for simulating the two states (up and down) of system components i.e. for component failure events. A modified customer damage model has been developed using most of the surveys conducted in different countries and their effects on customers. Using the data

collected from the surveys the most suitable model for calculating customer damage cost, will be formulated which can be applied in any country by changing the currency value and per capita income of the citizens.

In all the simulations EENS (MWh/yr.) is used as the index for System Reliability.

The EENS is represented by random variable 'x', for each case 'i' and it is evaluated using Equation 7.10.

$$x_i = \sum_{lp \in \mathcal{LP}} P U_{lp} * 8760 \quad \text{MWh/year} \quad (7.10)$$

Where, 'x' is for EENS, lp is state of load point, \mathcal{LP} is the cluster of failure sets of load points, P is the probability, U is the unavailability of load in state 'lp'.

The coefficient of variance is used as the criteria for convergence in the Monte Carlo simulation. It has been seen that the convergence rate for coefficient of convergence of EENS is the lowest. Therefore it is used as the convergence criteria for determining the accuracy of the results obtained. (Billinton, Li 1994)

7.8 MONTE CARLO SIMULATION METHOD USED FOR DETERMINING CUSTOMER DAMAGE COST

The time sequential MC method is used for finding the Customer Damage cost. All the steps for modelling the MATLAB program are described below. The simulation is performed on yearly basis considering the annual hours as 8760. All the components are assumed to be working perfectly at the beginning of the year. The weather conditions are not considered for simulations. The analysis is made considering the events having failure in one component; second order failures are not considered.

Steps of programming:

1. For each component in the system generate a random number and use them as Time To Failure (TTF) values, using the respective components failure probability distributions.
2. The component with least TTF and its location in network is evaluated as this causes the failure event 'j'.
3. Two random numbers generated for the components with least TTF are converted to Time To Repair (TTR) and Time To Switch (TTS) using probability distributions for the components repair and switching times.
4. Identify load points that are affected by the failed event 'j'.
5. Evaluation of the failure duration ' r_{ij} ' for the load point 'i' in the system.
6. Revenue not collected (RNC) and Interruption cost (COST) is evaluated for load point 'i' due to failure event 'j'.

$$RNC = L_i \cdot r_{ij} \quad (7.11)$$

$$COST = c_{ij} L_i \quad (7.12)$$

Where, L_i is the Electricity bill divided by number of hours in given period, r_{ij} is the outage duration and c_{ij} is the interruption cost.

7. RNC and COST is summed up to get the total values.
8. Steps 5-7 are repeated for every affected load point.
9. If the Total simulation time is less than the specified time then go to step 10 and if not, go to step 11.
10. A new random number is generated for the repair component, which is converted into a new TTF value then go to step 2.

11. RNC and Interruption cost for all load points are determined for the total simulation years.

12. ECOST is calculated using the following equation.

$$ECOST_i = COST_i / N \quad (7.13)$$

Where 'N' is the total number of simulation period specified in years.

7.9 RELIABILITY DATA FOR CALCULATION

For Calculating the Reliability worth a small radial distribution power system network is considered which is shown in Figure 7.4. The assumed length of ten overhead lines is given in Table 7.1. The Radial distribution system has six Load points and the percentage loading of each is provided in the ECOST results calculated using the percentage loading of all customers in Table No: 7.12-7.17. Six distribution system Transformer (11/0.4 kV) with Circuit Breakers (11 kV) are considered for each load point whose reliability data is provided in Table 7.3. The other fuses and isolators are assumed to be 100% reliable for the calculations.

Table: 7.1. Length of Overhead lines considered for distribution system case study.

LINE/CABLE	L1	L2	L3	L4	L5	L6	L7	L8	L9	L10
LENGTH (Km)	1	2.8	2.4	1.8	1.4	1.5	1.8	1	1.5	2.6

Source: (Billinton, Kumar et al. 1989)

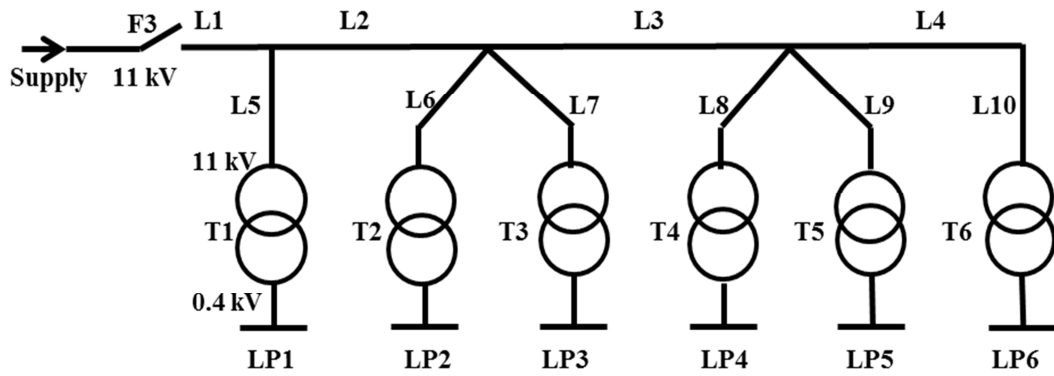


Figure 7.4: A small radial Distribution system network considered for case study.

Source: (Billinton, Kumar et al. 1989)

The mean and standard deviations for the customer damage function is taken from the thesis of Ran.M (2003) which is shown in Table 7.2. The Failure rates, restoration time and switching time of the system components are given in Table 7.3. The Failure rates for overhead lines is given in [f/yr.-km]

Table 7.2: The Customer Damage Function Data for a Number of Customers

NUMBER OF HOURS	CUSTOMER DAMAGE FUNCTION(CDF)									
	RETAIL		CLOTHING		METAL		GARAGE		HOTEL	
	MEAN	SD	MEAN	SD	MEAN	SD	MEAN	SD	MEAN	SD
1	0.82	0.53	2.2	1.44	4.65	6.37	0.74	0.67	0.45	0.18
2	1.02	0.5	5.48	3.54	8.77	12.66	1.56	1.23	0.92	0.32
4	1.72	1.12	10.08	6.82	14.08	19.93	3.06	2.76	1.93	0.95
8	5.52	3.67	20.3	14.88	22.01	33.62	4.82	3.66	3.7	1.93

Source: (M 2003)

Table 7.3: Reliability Data for System Network Components

SERIAL NUMBER	SYSTEM NETWORK COMPONENTS RELIABILITY DATA			
	SYSTEM COMPONENTS	λ_p [f/yr]	RT/RpT[hr]	SwT [hr]
1	TRANSFORMER(11/0.4 kV)	0.015	10	1
2	BREAKER (11kV)	0.006	4	1
3	OVERHEAD LINES (11 kV)	0.065	5	1

Source: (Billinton, Kumar et al. 1989)

Where, λ_p is the permanent failure rate, RT/RpT is the repair/ replacement time and SwT is the switching time.

7.10 RESULTS

As mentioned before, a small radial distribution system shown in Figure 7.4 is considered for estimating the Reliability worth. This radial distribution system is assumed to be the Load at Bus 7 of the 7-Bus System considered for the case study. EENS is calculated for the 7-Bus System at each load Bus and the EENS at Bus 7 is used to calculate IEAR index using the ECOST calculated for the radial distribution system. The IEAR index is calculated using Equation 7.3. This index at Bus 7 of the 7-Bus system will be added to the Transmission cost and Congestion cost at Bus-7 of the 7-Bus system to find the Total Transmission Costing Using Reliability Benefits. The results obtained using MC sampling approach for EENS is shown below. These results obtained were used as a part of the procedure to finally calculate ROTC.

7.10.1 7-BUS SYSTEM

The coefficient of Variance for the simple sampling and importance sampling methods obtained from the MATLAB program output of EENS, are shown in Figure 7.5 and Figure 7.6. As seen from the figure the coefficient of variance for EENS using simple sampling method is 0.00473 and using importance sampling method is 0.005483, which are very low. This shows the EENS value obtained using these methods are quite accurate.

The number of load curtailments per simulations for the 7-Bus system is shown in Table7.4. This gives the details of the Load curtailed per year for each simulations, which is generated using random numbers.

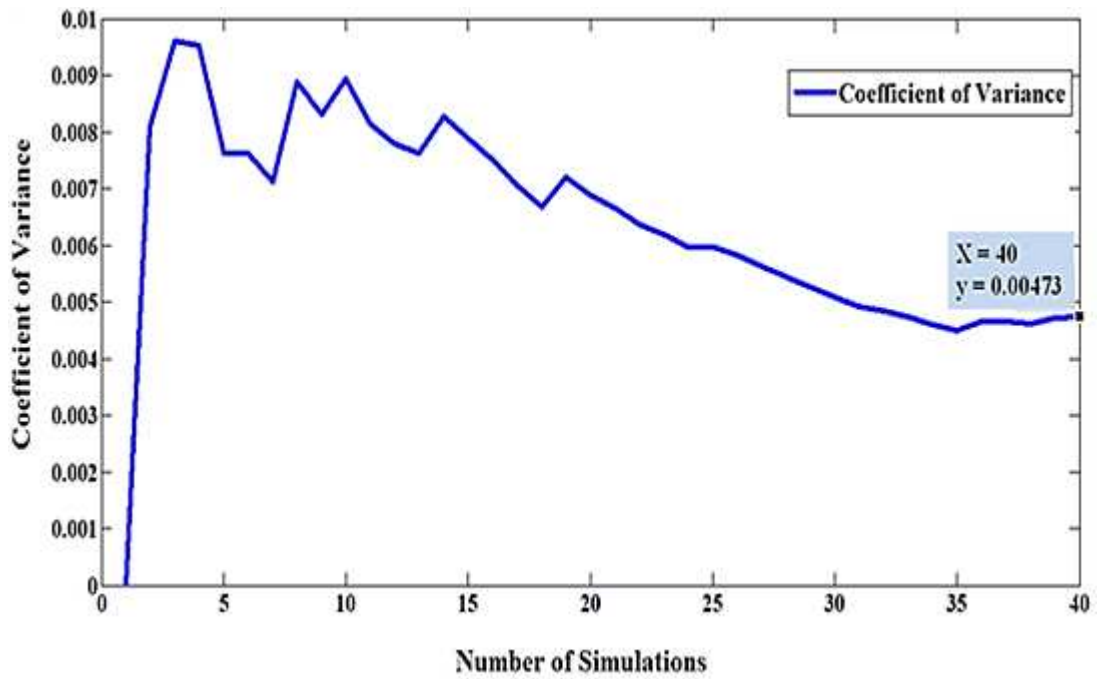


Figure 7.5: Coefficient of Variance Versus Number of Simulations using Simple Sampling for 7-Bus system

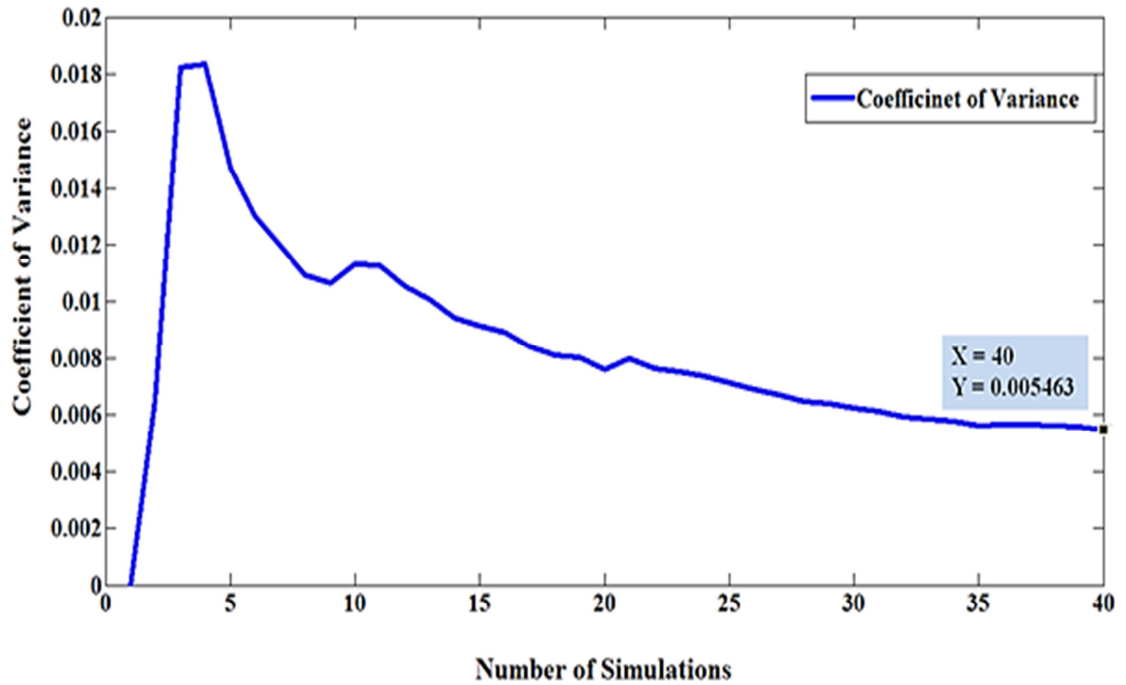


Figure 7.6: Coefficient of Variance Versus Number of Simulations using Importance Sampling for 7-Bus system

Table 7.4: Number of Load curtailments per Simulations for 7-Bus system

Number of Simulations	Number of Curtailment per Load Point in a Year					
	LOAD 2	LOAD 3	LOAD 4	LOAD 5	LOAD 6	LOAD 7
1	1399	1399	1399	1399	1399	1399
2	1433	1433	1433	1433	1433	1433
3	1457	1457	1457	1457	1457	1457
4	1388	1388	1388	1388	1388	1388
5	1418	1418	1418	1418	1418	1418
6	1380	1380	1380	1380	1380	1380
7	1442	1442	1442	1442	1442	1442
8	1340	1340	1340	1340	1340	1340
9	1442	1442	1442	1442	1442	1442
10	1339	1339	1339	1339	1339	1339
11	1415	1415	1415	1415	1415	1415
12	1366	1366	1366	1366	1366	1366
13	1450	1450	1450	1450	1450	1450
14	1494	1494	1494	1494	1494	1494
15	1377	1377	1377	1377	1377	1377
16	1439	1439	1439	1439	1439	1439
17	1415	1415	1415	1415	1415	1415
18	1425	1425	1425	1425	1425	1425
19	1318	1318	1318	1318	1318	1318
20	1390	1390	1390	1390	1390	1390
21	1441	1441	1441	1441	1441	1441
22	1421	1421	1421	1421	1421	1421
23	1448	1448	1448	1448	1448	1448
24	1391	1391	1391	1391	1391	1391
25	1350	1350	1350	1350	1350	1350
26	1446	1446	1446	1446	1446	1446
27	1397	1397	1397	1397	1397	1397
28	1418	1418	1418	1418	1418	1418
29	1396	1396	1396	1396	1396	1396
30	1400	1400	1400	1400	1400	1400
31	1419	1419	1419	1419	1419	1419
32	1443	1443	1443	1443	1443	1443
33	1442	1442	1442	1442	1442	1442
34	1401	1401	1401	1401	1401	1401
35	1383	1383	1383	1383	1383	1383
36	1490	1490	1490	1490	1490	1490
37	1355	1355	1355	1355	1355	1355
38	1461	1461	1461	1461	1461	1461
39	1490	1490	1490	1490	1490	1490
40	1352	1352	1352	1352	1352	1352

The EENS index calculated using simple and importance sampling method is shown in Table: 7.5 in which it can be seen that the EENS for the total 7-Bus system using both methods is nearly the same. Using simple sampling method the EENS for the total system is 84.91 (MWh/Hr) and using Importance sampling method it is 84.51 (MWh/Hr). In Table 7.6 the calculated values of probability of load curtailments and EDNS are shown, which are used for the calculation of EENS for each load and for the whole 7-Bus system.

Table 7.5: EENS results using Simple and Importance Sampling method for 7-Bus System

SIMPLE Sampling					IMPORTANCE Sampling	
LOADS	EENS [MWh/yr]	EENS [MWh/Hr]	SYSTEM EENS [MWh/yr]	SYSTEM EENS [MWh/Hr]	SYSTEM EENS [MWh/yr]	SYSTEM EENS [MWh/Hr]
LOAD 2	98937.19	11.29	743828.88	84.91	740332.2	84.51
LOAD 3	136038.6	15.53			Total Number of Samples:	
LOAD 4	49468.6	5.65			400000	
LOAD 5	160772.9	18.35	Total Simulation Time: (hr:min:sec)			
LOAD 6	149305.8	17.04	SIMPLE Sampling		IMPORTANCE Sampling	
LOAD 7	149305.8	17.04	0:15:47		01:11:10	

Table 7.6: Probability of Load curtailment and EDNS results for 7-Bus System

LOADS	PLC	EDNS [MW]
LOAD 2	0.14	11.29
LOAD 3	0.14	15.53
LOAD 4	0.14	5.65
LOAD 5	0.14	18.35
LOAD 6	0.14	17.04
LOAD 7	0.14	17.04
Total System	0.85	84.91

The capacity outage probability table for 7-Bus system is shown in Table 7.7, which has been evaluated considering 99% availability of generators during the year. These probabilities can be used to calculate LOLP and LOLE index for the generating system.

Table 7.7: Capacity Outage Table for the 7-Bus System

CAPACITY AVAILABLE	CAPACITY UNAVAILABLE	STATE PROBABILITY	CUMULATIVE PROBABILITY
160.00	0.00	0.96	1.00
120.00	40.00	0.04	0.04
80.00	80.00	0.00	0.00
40.00	120.00	0.00	0.00
0.00	160.00	0.00	0.00

7.10.2 IEEE 30-BUS SYSTEM

Figure 7.7 and 7.8 show the coefficient of Variance for the simple sampling and importance sampling methods obtained from the MATLAB program output of EENS, for the 30-Bus system. As seen from the figures the coefficient of variance for EENS using simple sampling method is 0.00175 and using importance sampling method it is 0.1502, which shows that the coefficient of variance using simple sampling method is very low compared to the importance sampling method. This shows the EENS value obtained using simple sampling method is more accurate than the values obtained using the importance sampling method.

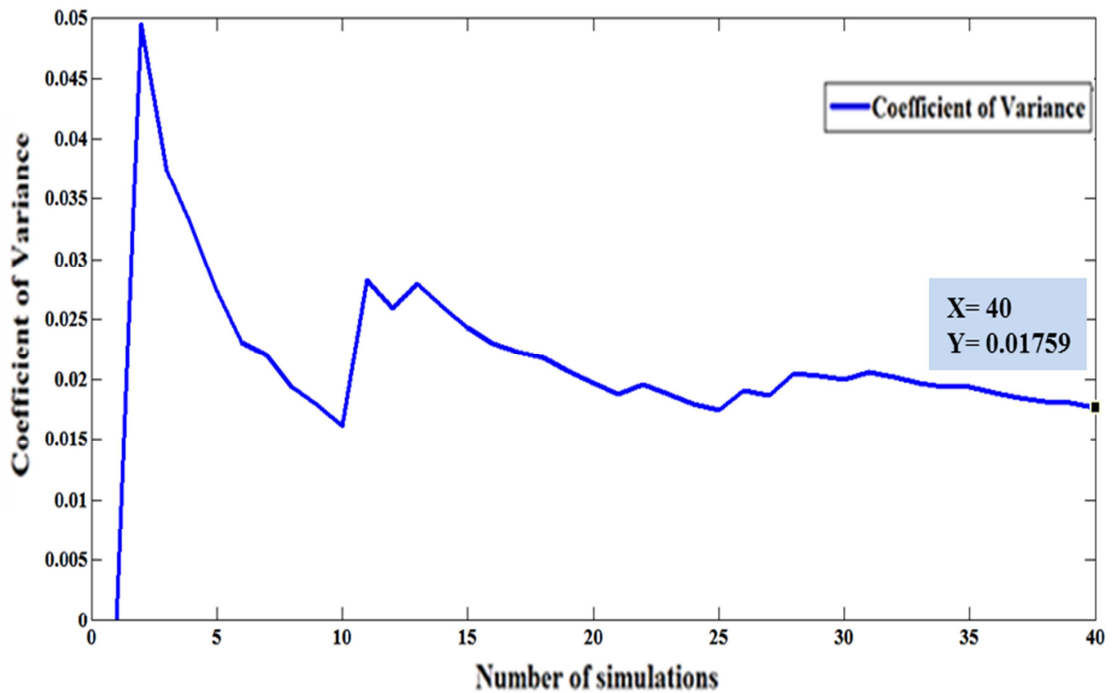


Figure 7.7: Coefficient of Variance Versus Number of Simulations using Simple Sampling for IEEE 30-Bus system

The number of load curtailments per simulation for the 30-Bus system is shown in Table 7.8. This gives the details of the Load curtailed per year for each simulation, which is generated using random numbers.

The EENS index calculated using simple and importance sampling method is shown in Table 7.9 in which it can be seen that the EENS for the total 30-Bus system using both method is nearly the same. Using simple sampling method the EENS for the total system is 0.33 (MWh/Hr) and using Importance sampling method it is 0.23 (MWh/Hr). In Table 7.10 the calculated values of probability of load curtailments and EDNS are shown, which are used for the calculation of EENS for each load and for the whole 30-Bus system.

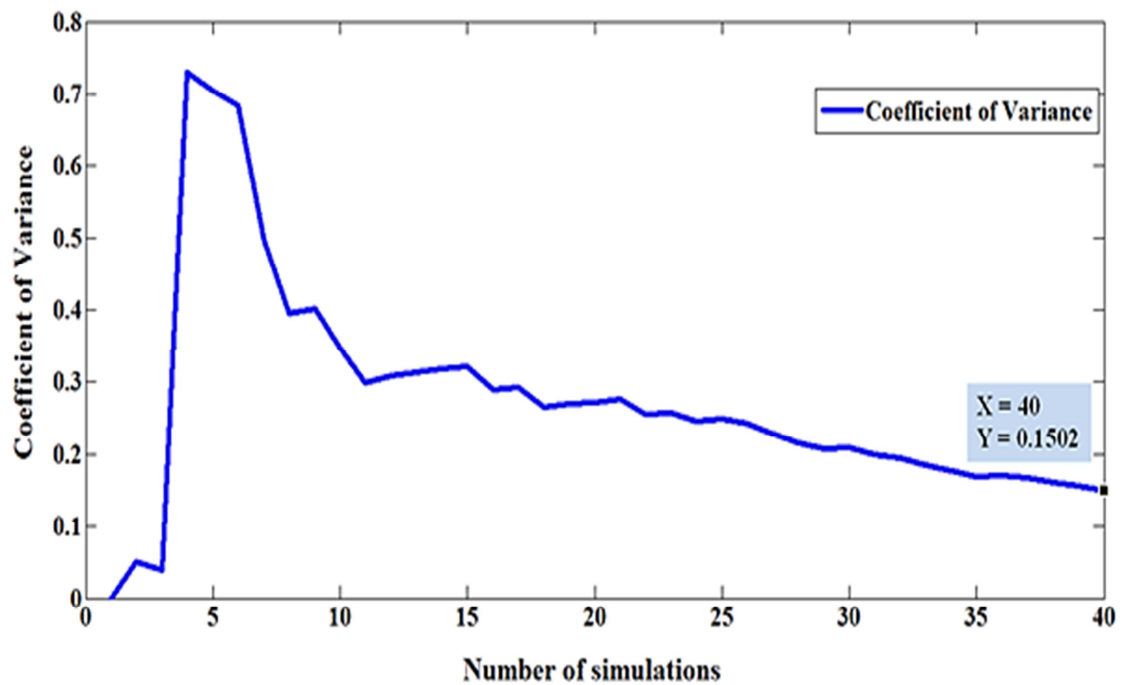


Figure 7.8: Coefficient of Variance Versus Number of Simulations using Importance Sampling for IEEE 30-Bus system

Table 7.8: Number of Load curtailments per Simulation for the IEEE 30-Bus system

No of Simulations	NUMBER OF CURTAILMENTS PER LOAD POINT																					
	LOAD 2	LOAD 3	LOAD 4	LOAD 7	LOAD 8	LOAD 10	LOAD 11	LOAD 12	LOAD 14	LOAD 15	LOAD 16	LOAD 17	LOAD 18	LOAD 19	LOAD 20	LOAD 21	LOAD 23	LOAD 24	LOAD 26	LOAD 29	LOAD 30	
1	0	296	35	0	0	0	1881	6	35	35	35	0	35	13	296	6	35	20	35	296	6	
2	2	303	43	0	0	0	1908	8	43	43	43	0	43	16	303	8	43	22	43	303	8	
3	0	289	34	0	0	0	1841	9	34	34	34	0	34	14	289	9	34	20	34	289	9	
4	3	288	37	1	0	0	1910	13	37	37	37	0	37	21	288	12	37	24	37	288	13	
5	0	303	37	0	0	0	1867	6	37	37	37	0	37	14	303	6	37	21	37	303	6	
6	0	327	34	0	0	0	1931	10	34	34	34	0	34	18	327	10	34	20	34	327	10	
7	0	318	43	0	0	0	1893	8	43	43	43	0	43	17	318	8	43	23	43	318	9	
8	0	294	41	0	0	0	1912	7	41	41	41	0	41	13	294	7	41	24	41	294	7	
9	2	295	34	2	0	0	1810	9	34	34	34	0	34	13	295	8	34	17	34	295	10	
10	0	309	40	0	0	0	1930	9	40	40	40	0	40	17	309	8	40	19	40	309	9	
11	0	268	23	0	0	0	1849	5	23	23	23	0	23	8	268	5	23	14	23	268	5	
12	1	305	36	0	0	0	1890	9	36	36	36	0	36	18	305	9	36	21	36	305	9	
13	0	274	27	0	0	0	1860	5	27	27	27	0	27	13	274	5	27	16	27	274	5	
14	2	312	29	1	0	1	1942	12	29	29	29	0	29	19	312	12	29	23	29	312	12	
15	1	295	32	0	0	0	1809	11	32	32	32	0	32	17	295	11	32	19	32	295	11	
16	0	259	35	0	0	0	1805	9	35	35	35	0	35	18	259	8	35	22	35	259	10	
17	1	307	42	1	0	0	1867	7	42	42	42	0	42	19	307	7	42	26	42	307	7	
18	0	302	33	0	0	0	1876	3	33	33	33	0	33	11	302	2	33	20	33	302	3	
19	1	303	39	0	0	0	1852	4	39	39	39	0	39	17	303	4	39	23	39	303	5	
20	0	297	38	0	0	0	1878	8	38	38	38	0	38	18	297	8	38	26	38	297	8	
21	1	288	33	0	0	0	1825	8	33	33	33	0	33	17	288	8	33	21	33	288	8	
22	0	301	24	0	0	0	1915	5	24	24	24	0	24	12	301	5	24	15	24	301	5	
23	0	269	38	0	0	0	1861	8	38	38	38	0	38	15	269	7	38	26	38	269	8	
24	1	301	38	1	0	0	1914	6	38	38	38	0	38	15	301	6	38	22	38	301	6	
25	0	282	32	0	0	0	1841	9	32	32	32	0	32	15	282	8	32	19	32	282	9	
26	0	298	22	0	0	0	1894	2	22	22	22	0	22	9	298	2	22	12	22	298	2	
27	0	315	42	0	0	0	1885	6	42	42	42	0	42	17	315	6	42	24	42	315	6	
28	1	269	23	1	0	0	1833	2	23	23	23	0	23	5	269	1	23	11	23	269	2	
29	1	259	32	1	0	0	1830	5	32	32	32	0	32	13	259	4	32	18	32	259	5	
30	0	290	28	0	0	0	1823	6	28	28	28	0	28	12	290	6	28	17	28	290	6	
31	1	312	46	0	0	0	1869	11	46	46	46	0	46	22	312	11	46	25	46	312	12	
32	1	340	38	0	0	0	1929	7	38	38	38	0	38	17	340	7	38	24	38	340	7	
33	0	312	42	0	0	0	1882	4	42	42	42	0	42	15	312	4	42	19	42	312	4	
34	0	299	31	0	0	0	1838	2	31	31	31	0	31	10	299	2	31	14	31	299	3	
35	1	301	45	1	0	0	1898	8	45	45	45	0	45	19	301	8	45	31	45	301	8	
36	1	306	36	1	0	0	1853	10	36	36	36	0	36	16	306	10	36	21	36	306	10	
37	0	309	29	0	0	0	1916	6	29	29	29	0	29	11	309	5	29	16	29	309	7	
38	0	304	42	0	0	0	1908	6	42	42	42	0	42	22	304	6	42	30	42	304	6	
39	0	324	41	0	0	0	1875	9	41	41	41	0	41	23	324	9	41	30	41	324	9	
40	0	278	34	0	0	0	1828	12	34	34	34	0	34	18	278	10	34	21	34	278	12	

Table 7.9: EENS results using Simple and Importance Sampling Method for the IEEE 30-Bus System

SIMPLE Sampling					IMPORTANCE Sampling	
LOADS	EENS [MWh/yr.]	EENS [MWh/Hr]	SYSTEM EENS [MWh/yr.]	SYSTEM EENS [MWh/Hr]	SYSTEM EENS [MWh/yr.]	SYSTEM EENS [MWh/Hr]
LOAD 2	9.20	0.00	2867.83	0.33	2020.14	0.23
LOAD 3	418.70	0.05				
LOAD 4	234.35	0.03				
LOAD 7	1.87	0.00	Total Number of Samples:			
LOAD 8	0	0				
LOAD 10	0.46	0.00				
LOAD 11	16.41	0.00	400000			
LOAD 12	69.90	0.01				
LOAD 14	191.18	0.02				
LOAD 15	203.21	0.02	Total Simulation Time: (hr : min : sec)			
LOAD 16	107.92	0.01				
LOAD 17	0	0				
LOAD 18	98.67	0.01				
LOAD 19	90.52	0.01				
LOAD 20	573.39	0.07	SIMPLE Sampling		IMPORTANCE Sampling	
LOAD 21	26.98	0.00				
LOAD 23	98.67	0.01	00:28:27		2:19:36	
LOAD 24	130.99	0.01				
LOAD 26	107.92	0.01				
LOAD 29	418.70	0.05				
LOAD 30	68.79	0.01				

Table 7.10: Probability of Load curtailment and EDNS results for the IEEE 30-Bus System

Simple Sampling		
LOADS	PLC	EDNS
LOAD 2	0.00	0.00
LOAD 3	0.03	0.05
LOAD 4	0.00	0.03
LOAD 7	0.00	0.00
LOAD 8	0.00	0.00
LOAD 10	0.00	0.00
LOAD 11	0.19	0.00
LOAD 12	0.00	0.01
LOAD 14	0.00	0.02
LOAD 15	0.00	0.02
LOAD 16	0.00	0.01
LOAD 17	0.00	0.00
LOAD 18	0.00	0.01
LOAD 19	0.00	0.01
LOAD 20	0.03	0.07
LOAD 21	0.00	0.00
LOAD 23	0.00	0.01
LOAD 24	0.00	0.01
LOAD 26	0.00	0.01
LOAD 29	0.03	0.05
LOAD 30	0.00	0.01
Total System	0.31	0.33

7.10.3 INDIAN UTILITY 146-BUS SYSTEM

The coefficient of Variance for the simple sampling method for the Indian Utility 146-Bus system is shown in Figure 7.9. As seen from the figure the coefficient of variance for EENS using simple sampling method is 0.001536, which shows that the coefficient of variance using simple sampling method is very low. This shows that the EENS value obtained using simple sampling method is quite accurate.

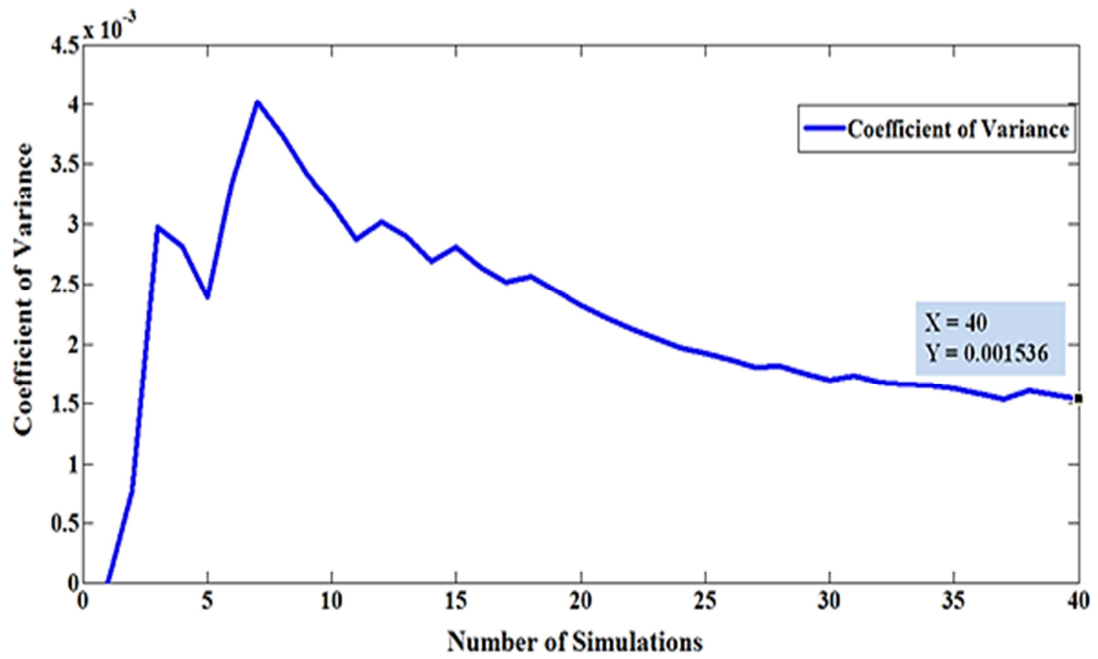


Figure 7.9: Coefficient of Variance Versus Number of Simulations using Simple Sampling for the Indian Utility 146-Bus system

The number of load curtailments per simulation for the Indian Utility 146-Bus system is shown in Appendix-E. (CD enclosed). This gives the details of the Load curtailed per year for each simulation, which is generated using random numbers. The EENS index calculated using simple sampling method is shown in Table 7.11 in which it can be seen that the EENS for the total 146-Bus system using simple sampling method is 202.89 (MWh/Hr). In Table 7.11 the calculated values of probability of load curtailments and EDNS for total system are shown, which are used for the calculation of EENS for whole 146-Bus system.

Table 7.11: EENS results using Simple Sampling Method for the Indian Utility 146-Bus System

SIMPLE Sampling				
Total PLC	Total EDNS [MW]	Total EENS [MWh/yr.]	Total Number of Samples	Total Simulation Time (hr :min :s)
36.6774	202.895	1777357	400000	08:11:52

The probability of load curtailments and EDNS for every load on the Indian Utility 146-Bus system is provided in Appendix-E. (CD enclosed)

The ECOST has been calculated for all the six load points of radial distribution system using time sequential approach and the results of ECOST, for the customer damage function taken at 1,2,4,and 8 hours duration are shown in Tables 7.12, 7.13, 7.14, 7.15, 7.16 and 7.17. The percentage loading is the percentage of load that the consumer is putting on a particular Bus and this is an assumed value. The percentage loading is considered in-order to evaluate the value of ECOST for different consumers loading conditions at different load points. Then the total ECOST for a particular load point is calculated taken the mean and summation of mean in \$/hr. This process is repeated at each load point LP1-LP6 of the radial distribution system and the ECOST then calculated at each load point is then summed up together to find the Total ECOST of the radial distribution system, which is actually the ECOST at Bus 7 of the 7-Bus system.

As EENS is evaluated and shown in Table 7.5 for a load at Bus 7, this can be used along with ECOST calculated at Bus 7 to calculate IEAR index using Equation 7.3 which is shown in Table 7.18.

$$\text{i.e. } IEAR_{BUS\ 7} = \frac{0.2807}{17.04} = 0.01647 \frac{\$}{MWh} = 1.647 * 10^{-5} \$/kWh$$

So, the evaluated IEAR_{Bus 7} is $1.647 * 10^{-5}$ \$/kWh for Bus 7 of the 7-Bus system.

Likewise if the reliability data for the distribution system is known at each load connected to the system, then IEAR can be calculated for whole system. Which can be further used to calculate the reliability worth of the whole system.

Table 7.12: ECOST results for Load Point-1 at Bus-7 of the 7-Bus System

ECOST Calculations of LP-1 of 7 Bus															
No. of Hours	RETAIL			CLOTHING			METAL			GARAGE			HOTEL		
	CDF		ECOST	CDF		ECOST	CDF		ECOST	CDF		ECOST	CDF		ECOST
	MEAN	SD		MEAN	SD		MEAN	SD		MEAN	SD		MEAN	SD	
1	0.82	0.53	13.81	2.2	1.44	37.21	4.65	6.37	118.57	0.74	0.67	14.72	0.45	0.18	6.23
2	1.02	0.5	15.07	5.48	3.54	92.28	8.77	12.66	234.61	1.56	1.23	28.96	0.92	0.32	12.10
4	1.72	1.12	29.06	10.08	6.82	173.53	14.08	19.93	369.61	3.06	2.76	61.41	1.93	0.95	28.85
8	5.52	3.67	93.77	20.3	14.88	363.86	22.01	33.62	609.85	4.82	3.66	87.59	3.7	1.93	56.24
Mean			37.93	Mean		166.72	Mean		333.16	Mean		48.17	Mean		25.86
% Loading			14.00	% Loading		10.00	% Loading		35.00	% Loading		21.00	% Loading		20.00
ECOST for % Loading			5.31	ECOST for % Loading		16.67	ECOST for % Loading		116.61	ECOST for % Loading		10.12	ECOST for % Loading		5.17
ECOST Total (\$/Hr)			153.87												

Table 7.13: ECOST results for Load Point-2 at Bus-7 of the 7-Bus System

ECOST Calculations of LP-2 of 7 Bus															
No. of Hours	RETAIL			CLOTHING			METAL			GARAGE			HOTEL		
	CDF		ECOST	CDF		ECOST	CDF		ECOST	CDF		ECOST	CDF		ECOST
	MEAN	SD		MEAN	SD		MEAN	SD		MEAN	SD		MEAN	SD	
1	0.82	0.53	26.56	2.2	1.44	71.63	4.65	6.37	223.52	0.74	0.67	28.08	0.45	0.18	12.09
2	1.02	0.5	29.30	5.48	3.54	175.54	8.77	12.66	432.07	1.56	1.23	55.22	0.92	0.32	23.73
4	1.72	1.12	55.87	10.08	6.82	332.52	14.08	19.93	688.41	3.06	2.76	116.60	1.93	0.95	55.83
8	5.52	3.67	180.82	20.3	14.9	697.30	22.01	33.62	1134.10	4.82	3.66	167.72	3.7	1.93	109.78
Mean			73.14	Mean		319.25	Mean		619.53	Mean		91.91	Mean		50.36
% Loading			6.00	% Loading		21.00	% Loading		42.00	% Loading		25.00	% Loading		6.00
ECOST for % Loading			4.39	ECOST for % Loading		67.04	ECOST for % Loading		260.20	ECOST for % Loading		22.98	ECOST for % Loading		3.02
ECOST Total (\$/Hr)			357.63												

Table 7.14: ECOST results for Load Point-3 at Bus-7 of the 7-Bus System

ECOST Calculations of LP-3 of 7 Bus															
No. of Hours	RETAIL			CLOTHING			METAL			GARAGE			HOTEL		
	CDF		ECOST	CDF		ECOST	CDF		ECOST	CDF		ECOST	CDF		ECOST
	MEAN	SD		MEAN	SD		MEAN	SD		MEAN	SD		MEAN	SD	
1	0.82	0.53	27.83	2.2	1.44	74.91	4.65	6.37	234.99	0.74	0.67	29.58	0.45	0.18	12.75
2	1.02	0.5	30.88	5.48	3.54	185.23	8.77	12.66	454.82	1.56	1.23	58.29	0.92	0.32	25.07
4	1.72	1.12	58.36	10.08	6.82	348.84	14.08	19.93	726.19	3.06	2.76	121.70	1.93	0.95	58.52
8	5.52	3.67	189.17	20.3	14.88	727.02	22.01	33.62	1179.5	4.82	3.66	175.64	3.7	1.93	115.44
Mean			76.56	Mean		334.00	Mean		648.90	Mean		96.30	Mean		52.95
% Loading			15.00	% Loading		18.00	% Loading		38.00	% Loading		21.00	% Loading		8.00
ECOST for % Loading			11.48	ECOST for % Loading		60.12	ECOST for % Loading		246.58	ECOST for % Loading		20.22	ECOST for % Loading		4.24
ECOST Total (\$/Hr)			342.64												

Table 7.15: ECOST results for Load Point-4 at Bus-7 of the 7-Bus System

ECOST Calculations of LP-4 of 7 Bus															
No. of Hours	RETAIL			CLOTHING			METAL			GARAGE			HOTEL		
	CDF		ECOST	CDF		ECOST	CDF		ECOST	CDF		ECOST	CDF		ECOST
	MEAN	SD		MEAN	SD		MEAN	SD		MEAN	SD		MEAN	SD	
1	0.82	0.53	35.02	2.2	1.44	94.39	4.65	6.37	291.42	0.74	0.67	36.90	0.45	0.18	16.04
2	1.02	0.5	38.88	5.48	3.54	231.67	8.77	12.66	568.41	1.56	1.23	72.95	0.92	0.32	31.35
4	1.72	1.12	73.46	10.08	6.82	436.83	14.08	19.93	901.19	3.06	2.76	152.35	1.93	0.95	73.85
8	5.52	3.67	238.66	20.3	14.88	907.62	22.01	33.62	1471.97	4.82	3.66	220.63	3.7	1.93	144.30
Mean			96.51	Mean		417.63	Mean		808.25	Mean		120.71	Mean		66.39
% Loading			9.00	% Loading		12.00	% Loading		48.00	% Loading		17.00	% Loading		14.00
ECOST for % Loading			8.69	ECOST for % Loading		50.12	ECOST for % Loading		387.96	ECOST for % Loading		20.52	ECOST for % Loading		9.29
ECOST Total (\$/Hr)			476.57												

Table 7.16: ECOST results for Load Point-5 at Bus-7 of the 7-Bus System

ECOST Calculations of LP-5 of 7 Bus															
No. of Hours	RETAIL			CLOTHING			METAL			GARAGE			HOTEL		
	CDF		ECOST	CDF		ECOST	CDF		ECOST	CDF		ECOST	CDF		ECOST
	MEAN	SD		MEAN	SD		MEAN	SD		MEAN	SD		MEAN	SD	
1	0.82	0.53	36.90	2.2	1.44	100.05	4.65	6.37	309.25	0.74	0.6	39.15	0.45	0.18	17.11
2	1.02	0.5	41.21	5.48	3.54	247.31	8.77	12.66	604.21	1.56	1.2	77.13	0.92	0.32	33.42
4	1.72	1.12	77.99	10.08	6.82	462.66	14.08	19.93	956.18	3.06	2.7	160.90	1.93	0.95	78.35
8	5.52	3.67	251.80	20.3	14.88	971.60	22.01	33.62	1563.2	4.82	3.6	234.82	3.7	1.93	153.51
Mean			101.97	Mean		445.41	Mean		858.22	Mean		128.00	Mean		70.60
% Loading			12.00	% Loading		17.00	% Loading		40.00	% Loading		18.00	% Loading		13.00
ECOST for % Loading			12.24	ECOST for % Loading		75.72	ECOST for % Loading		343.29	ECOST for % Loading		23.04	ECOST for % Loading		9.18
ECOST Total (\$/Hr)			463.46												

Table 7.17: ECOST results for Load Point-6 at Bus-7 of the 7-Bus System

ECOST Calculations of LP-6 of 7 Bus															
No. of Hours	RETAIL			CLOTHING			METAL			GARAGE			HOTEL		
	CDF		ECOST	CDF		ECOST	CDF		ECOST	CDF		ECOST	CDF		ECOST
	MEA	SD		MEAN	SD		MEAN	SD		MEAN	SD		MEAN	SD	
1	0.82	0.53	49.82	2.2	1.44	134.41	4.65	6.37	414.65	0.74	0.67	52.21	0.45	0.18	22.97
2	1.02	0.5	55.80	5.48	3.54	331.36	8.77	12.66	805.11	1.56	1.23	103.32	0.92	0.32	45.22
4	1.72	1.12	104.78	10.08	6.82	623.60	14.08	19.93	1274.73	3.06	2.76	216.24	1.93	0.95	105.36
8	5.52	3.67	339.67	20.3	14.88	1300.82	22.01	33.62	2101.95	4.82	3.66	313.23	3.7	1.93	206.81
Mean			137.52	Mean		597.55	Mean		1149.11	Mean		171.25	Mean		95.09
% Loading			10.00	% Loading		15.00	% Loading		45.00	% Loading		20.00	% Loading		10.00
ECOST for % Loading			13.75	ECOST for % Loading		89.63	ECOST for % Loading		517.10	ECOST for % Loading		34.25	ECOST for % Loading		9.51
ECOST Total (\$/Hr)			664.24												

Table 7.18: Interruption Energy Assessment Rate Calculated at 7th bus of the 7-Bus System

Total ECOST (\$/yr)	Total ECOST (\$/Hr)	IEAR		
		EENS (MWh/Hr) at Bus 7 of 7-Bus system	IEAR (\$/MWh) at Bus 7 of 7-Bus system	IEAR (\$/kWh)
2458.43	0.2807	17.04	0.01647	1.647×10^{-5}

7.11 SUMMARY

The key objective for undertaking the Reliability worth studies is to estimate all the Reliability Indices required in finding out the cost of providing reliable service to the consumers which will further be used for the formation of DMF for ROTC. This has been undertaken primarily for a transmission system, so a small radial distribution is considered for the study and the results are evaluated only for the Load at one bus of the 7- Bus system. But this approach shows that if all the reliability data for loads (Distribution system) at Buses are known, then total reliability worth evaluation can be achieved. In the process of calculating the Reliability indices required to find the worth of reliability our proposed MAPA has been applied using different methods of MC simulation, either to compare or to determine the results. Two VRT methods are used to find EENS at each load for the complete system in all the three cases i.e. 7-Bus, 30-Bus and 146 Bus systems. Also both the methods are compared according to their speed of simulation and also for their accuracy in terms of the Coefficient of variance. A time sequential Monte Carlo method is used for finding the customer damage cost in terms of ECOST index. EENS for 7 Bus and ECOST for 7 Bus are

used to find the IEAR index, which is actually the reliability worth for that bus in a 7-Bus system. Finally as stated in the previous sections summary results and relevant analysis have been presented in the appropriate sections with the detailed results of the studies and simulations conducted shown in the relevant Appendices due to their large volume.

PART-4

- 1. GENERAL DISCUSSION**
- 2. CONCLUSION AND FUTURE WORK**

CHAPTER - 8

8.1 GENERAL DISCUSSION

This chapter will provide a summary and discussion of the four part DMF for ROTC evaluation devised and reported with case studies within the thesis. The overall research findings, methodological issues, will be discussed and implications for contributing and advancing the knowledge in the field of ROTC and its practical applications will be explained.

The major aim of this research was to investigate and develop a DMF for ROTC, a transmission costing approach that includes capacity use and congestion cost based on reliability worth. In the literature review section it has been shown that transmission system pricing to date has been considered by focusing on a variety of subsidiary aspects of the issue and a holistic integrative approach (DMF) to ROTC was missing. In the approach reported here it is possible to undertake a complete estimation of transmission costs that includes capacity use cost, including the congestion cost based on the worth of system reliability. A section-wise discussion of methods and results are as follows.

8.1.1 FINDINGS FROM THE LITERATURE REVIEW

In the literature review section the topics considered were ATC, Congestion pricing, Distribution Factors, Transmission pricing and Reliability worth analysis. The reason of selecting these topics for the literature review is because all the above mentioned topics are necessary to evaluate and model transmission costing using reliability benefits (derived from reliability worth) and congestion cost (ROTC), for a particular region or a country. ATC review was necessary to inform our investigations for an

overview of the methods used for finding the capability of transmission lines for transmitting electrical power which can be further used for finding the appropriate method for calculating each cost component contribution to transmission costs in the transmission network. Congestion pricing and its management provides the overview of presently used methods and their significance in Transmission costing. Distribution factors are reported in the literature for undertaking sensitivity analysis and they have central importance in these studies. The transmission pricing review provided information on the methods being used in different countries and the process of implementation, and was important in devising the DMF. The reliability review showed the necessity for and significance of an inclusive reliability approach to costing in the present deregulated ESI for operating electrical transmission systems more efficiently and socio-economically.

It has been found from the literature review that a holistic integrative approach (DMF) to ROTC was missing. It was also found that there was a lack of a generally agreed equitable way of costing congestion pricing faced by consumers. It was suggested that PTDFs that were used as sensitivity factors can be used for determining the congestion cost (Minghai Liu, Gross 2004). There is urgent necessity for a new pricing scheme in India as explained in the rationale section as well due to high T&D losses, inability to recover the capital for energy supplied and also lack of proper transparent and explicit implementation of reliability factors in the planning and operation of electrical networks. One of the major objectives for any transmission system should be to achieve a highly reliable system subject to a range of socio-economic and financial constraints. Reliability is also considered when developing and expanding their system whilst charging equitable prices for the

transmission services. This is to strengthen the financial position, by facilitating effective revenue collection for cost recovery and future investments of the ESI companies.

8.1.2 LOAD FLOW STUDIES

The results discussed in this section mainly correspond to the first part of the DMF devised for obtaining ROTC.

A load flow study is the backbone of power system research and analysis, and our DMF for ROTC, as it provides the information regarding voltage, phase angle, reactive and active power at each section of the system. Case studies have been undertaken to verify and cross validate the approach with studies reported in the literature. Initially all ROTC techniques within the DMF were implemented on the 7 Bus System to test the model's algorithm and the programming code described in the relevant methodology sections. Once these models and algorithms and the associated programmes were proven to work with results and cross validated with similar studies from the literature, additional case studies were also undertaken with larger networks, i.e the IEEE 30 Bus system and an Indian Utility network. As seen from the results obtained for the unconstrained case of the 7-Bus system in Table 4.1 and 4.2, the power injected at each bus with the level of voltage and its phase angle can be analysed. Also the line flow in each transmission line connected between different buses can be evaluated. The results of the load flow studies have been used to calculate the complete transmission costing of the system using Reliability benefits. Similar results are shown in Tables 4.5-4.6 and Tables C.4-C.5 for the IEEE 30-Bus system and the Indian utility 146-Bus system.

8.1.3 TRANSMISSION COSTING STUDIES

The results discussed in this section mainly correspond to the second part of the DMF devised for obtaining ROTC.

In the Transmission costing part of the DMF for ROTC, five methods have been analysed, three MW-Mile methods i.e. Reverse, Absolute and Dominant MW Mile method, Bialek's Method and the proposed application of PTDF Method. This was undertaken to verify that subsidiary parts and techniques of our devised DMF for ROTC would result in comparable results with comparable techniques whilst resulting in a more equitable and effective ROTC.

As a result of the case studies and analysis carried out it has been found that for the 7-Bus system the Transmission Costing is 78.73 \$/MW using the proposed application of PTDF method, 59.23 \$/MW using Bialek's method, 71.34 \$/MW using Absolute MW-Mile method, 46.05 \$/MW using Reverse MW-Mile method and 58.69 \$/MW using Dominant MW-Mile method. All these results show that transmission costing for the 7-Bus system using the proposed application of PTDF method and Absolute MW-Mile method are comparable and nearly the same. This is because both methods consider the positive and negative contributions of generators on the line flow between transmission lines. Hence it can be concluded that the proposed application of PTDF method can recover the complete cost of the transmission capacity used and also enables the transmission service provider to have sufficient revenue for future modifications and extension of the transmission network.

For the 30-Bus system the obtained results for total transmission cost using the proposed application of PTDF method is 178.26 (\$/MW), which is the same as the

cost obtained using Bialek's method. Also the comparison of the transmission cost using the proposed application of PTDF method with Absolute MW Mile method gives similar results i.e. 170.69 (\$/MW). This comparison shows that results obtained by the proposed application of PTDF method is justified as the results can be verified by widely accepted and used methods and therefore can be used for estimating the transmission cost of the transmission system.

For the Indian Utility 146-Bus system the obtained results for total transmission cost using the proposed application of PTDF method is 1449.26 (\$/MW), which is slightly more than the cost obtained using Bialek's method which is 1118.23 (\$/MW). But by comparing the transmission cost using the proposed application of PTDF method with Absolute MW Mile method it gives a slightly lower value i.e. 1154.62 (\$/MW).

After analysing the cost obtained from all of the results it can be seen that the cost obtained from the the proposed application of PTDF method is more than all the mentioned methods, so this method is also justified as it obtains sufficient revenues for the transmission system operators for future development and present maintenance.

8.1.4 CONGESTION COSTING STUDIES

The results discussed in this section mainly correspond to the third part of the DMF devised for obtaining ROTC.

It is known that congestion in transmission systems is the key issue in terms of system security. In these studies a novel method has been proposed to find the congestion costing in a deregulated electricity market. The method proposed is based upon PTDF which has previously been used and reported as a sensitivity factor in

power system analysis. It has also been suggested by (Minghai Liu, Gross 2004), for future work, that PTDF can also be used for determination of congestion costs in transmission systems.

In this part the newly developed application of PTDF method and Bialek's method were utilized and compared for proving the viability of the proposed method in improving the decision making process.

As a result of the case studies and analysis conducted, the proposed application of PTDF method has been implemented and compared with Bialek's method to justify the viability of the obtained results for the 7-Bus system, IEEE 30-Bus system and Indian Utility 146-Bus system.

The purpose of this section is to find the contribution of generator and load on the Power flow in transmission lines and then to assign the congestion price to the loads responsible for the congestion in these lines. Two cases are considered for the analysis, unconstrained case and a constrained case. The total generation cost is determined for constrained and unconstrained cases. The corrective action policy is considered for relieving the congestion of overloaded lines. This can be achieved by redispatching the generators using Equation 6.15.

The TCC calculated after the re-dispatch of generators is assigned to all the congested lines according to their contribution for congestion costing. The impact of the congested lines is estimated by disconnecting the congested lines one by one and calculating the TCC for each case. This impact known as Relief Cost, which is the change in the generation cost after disconnecting a congested line, helps to apportioned TCC among each congested line.

For the 7-Bus system, after running a Newton-Raphson AC Load Flow three Transmission lines, Line 1-2, Line 3-4 and Line 4-5, were found to be congested.

As seen from the results in Table 6.10 and Table 6.11, the congestion cost using Bialek's method is found to be 206 \$/Hr and using the proposed application of PTDF method it is 206.19 \$/Hr, which is almost the same. The transmission cost per year for generator contribution can also be estimated using the proposed application of PTDF method and this has also been verified by comparing the results with Bialek's method shown in Figure: 6.6. This shows the validation of the proposed application of PTDF method and justifies that the proposed application of PTDF method can also be used for determination of congestion costs in transmission system networks.

For the 30-Bus system, after running a Newton-Raphson AC Load Flow, one transmission lines, Line 16-17, is found to be congested. The Line flow of the transmission line 16-17 in the constrained case has been changed from 16.96 MW to 15.88 MW after re-dispatch of generators and is now under the line limit of 16 MW. It can be seen from Table: 6.13, using Bialek's Method, that generation at bus 1 is reduced and generation at bus 21 has increased during re-dispatch to relieve the congestion in the transmission lines. The increase in generator cost, which is also termed as the Total Congestion Cost (TCC) is given in Table: 6.13. The TCC for the IEEE 30-Bus system is found to be -15.80 (\$/Hr).

By comparing the results obtained using the proposed application of PTDF method in Table: 6.12 and Bialek's method in Table: 6.13 it is found that both the methods result in a similar cost for congestion i.e. according to Bialek's method the congestion cost is -15.8(\$/Hr) and from the proposed application of PTDF method it is -16.68 (\$/Hr).

For the Indian Utility 146-Bus system, after running a Newton-Raphson AC Load Flow two Transmission lines, Line 28-27 and line 28-34 are found to be congested. The line flow of the transmission line 28-27 in the constrained case has been changed from -343.15 MW to -201.53 MW and for line 28-34 in the constrained case has been changed from -974.68 MW to -897.65 MW after re-dispatch of generators and both are now under the respective line limits of 300 MW and 900 MW. It can be seen from the constrained case load flow Table provided in Appendix-E (CD enclosed), using Bialek's Method that generation at buses 28, 29, 34, 36, 37, 58, 61, 62 and 88 is reduced and the generation at buses 1, 38, 49, 63, 75, 79 and 83 has increased during re-dispatch to relieve the congestion in the transmission lines. The increase in generator cost, which is also termed the Total Congestion Cost (TCC) is given in Table 6.14. The TCC for the Indian Utility 146-Bus system shown in Table 6.14 is found to be -2098.43 (\$/Hr). By comparing the results obtained using the proposed application of PTDF method in Table: 6.14 and Bialek's method in Table 6.15 it is found that both methods result in a similar cost for congestion i.e. according to Bialek's method the congestion cost is -2098.43(\$/Hr) and from the proposed application of PTDF method it is -2417.61 (\$/Hr).

The congestion cost for IEEE 30-Bus system and Indian Utility 146-Bus system are found to be negative. The reason being that in-order to relieve the congestion state the re-dispatch of generators results in a lower operating cost for generation i.e. a more economic generation.

The congestion cost evaluated in our study is 76.51 \$/MW which is equivalent to 0.0076 \$/KW, and the applicable congestion charges as per CERC order are

Rs.5.45/unit in India (Sharma 2013), which is nearly the same as the results obtained in our investigations, after conversion of currency.

In this study the transmission costing for all the systems using both the methods have been determined and the results found were similar, which justifies the validity of the new proposed approach for finding transmission congestion costs.

8.1.5 RELIABILITY BENEFITS VALUE EVALUATION

The results discussed in this section mainly correspond to the fourth part of the DMF devised for obtaining ROTC. In these studies relating to the final part for determining the worth of Reliability in power system our proposed MAPA has been used.

In this section some Monte Carlo Variance Reduction Techniques (MC-VRT) are used for the determination of Reliability indices such as:

- i) EENS
- ii) ECOST &
- iii) IEAR index

As described above this consists of using different methods of Monte Carlo simulation approach at different stages of calculation i.e. for determining the EENS index at each bus of the 7-Bus system two MC-VRT were used, i.e. Simple sampling and Importance sampling. Simple sampling was used to compare and validate the results and Importance sampling for its accuracy in terms of the coefficient of variance (Billinton, Li 1994).

The time sequential Monte Carlo Simulation method is used to determine the customer damage cost in terms of the ECOST index. This method is used because it reproduces the random behaviour of Power systems; it takes the input as random

variables and considers these values according to their probability distribution. TTF (Time to Failure) is exponentially distributed and the load point indices distribution is obtained by repeating the process many times. The time sequential approach allows the inclusion of time domain in reliability analysis, which allows modelling of the system to be past dependent (Jun, Bouchard-Coté 2014, Billinton, Li 1994).

The approach that has been taken (as discussed above) can be summarised as follows:

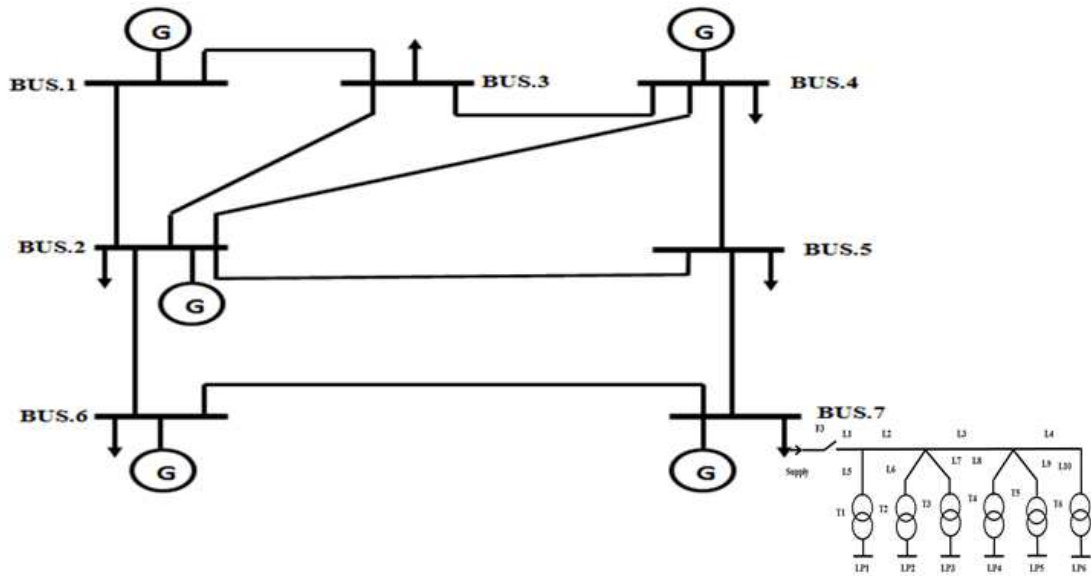


Figure 8.1: A Small radial network connected to 7th Bus of 7-Bus system

In this study a small distribution network system shown in Figure 7.4 is used, which is assumed to be connected at the 7th bus of the 7-Bus system which is shown above in Figure 8.1. The EENS at all the buses of the 7-Bus system are calculated as shown in Table: 7.5, from which the EENS at the 7th Bus is taken and used along with the ECOST calculated for the distribution system connected to the 7th bus.

The percentage loading is considered in-order to evaluate the value of ECOST for different consumers loading conditions at different load points. Then the total ECOST for a particular load point is calculated taking the mean and summation of

mean in \$/hr. This process is repeated at each load point, LP1-LP6, of the radial distribution system and the ECOST calculated at each load point is then summed together to find the Total ECOST of the radial distribution system, which is actually the ECOST at the 7th bus of the 7-Bus system.

Table 8.1: Transmission charges using load Contribution by PTDF method for 7- Bus System

TRANSMISSION CHARGES FOR LOAD CONTRIBUTION								
LINES		LINE COST	PTDF METHOD					
FROM	TO		LOAD 2	LOAD 3	LOAD 4	LOAD 5	LOAD 6	LOAD 7
1	2	1000	19512.68	-9534.18	6600.05	26330.96	46236.31	43690.91
1	3	1000	-103.87	36221.29	3104.35	5208.35	2285.71	4831.10
2	3	1000	-5570.50	45674.61	1843.97	-1165.58	-10193.00	-6459.75
2	4	1000	-10328.9	-1471.89	15035.78	17629.23	-9531.76	6758.75
2	5	1000	-3355.33	391.30	6263.96	48964.27	17371.05	43130.42
2	6	1000	-26877.6	-34390.21	-9366.21	-15770.24	84477.27	36148.75
4	3	1000	-5794.87	-28269.79	4888.07	3846.95	-8208.55	-1929.91
4	5	1000	-5614.58	-15291.54	-14821.5	38553.63	8532.69	31101.84
5	7	1000	9302.57	15357.64	8723.91	43022.67	-25072.10	-73400.62
6	7	1000	-3736.41	-2570.97	2204.42	21834.32	-57669.56	94001.91
TC (\$)		10000	-32566.9	6116.26	24476.77	188454.5	48228.06	177873.4
TOTAL TRANSMISSION CHARGES (\$)			412582.12					
TRANSMISSION CHARGES FOR EACH TRANSACTION (\$)			-789.34	148.24	593.26	4567.69	1168.93	4311.22
COST (\$/MW)			-9.87	1.35	14.83	35.14	5.84	21.5561
			68.85					

To determine the IEAR index at the 7th bus of the 7-Bus system Equation 7.3 is used.

The calculated IEAR for the bus is 0.01647 \$/MWh i.e. 3.294 \$ per 200MWh.

8.1.6 FINAL PHASE FOR INTEGRATION OF ALL COSTS

This value of IEAR along with the congestion cost and transmission costing at the 7th bus of the 7-Bus system will provide the complete ROTC for that bus. i.e.

ROTC = Transmission Costing_{7th-Bus} (From Table 8.1) + Congestion Costing_{7th Bus} (From Table 6.11) + IEAR_{7th Bus} (From Table 7.18).

$$= 4311.22 + 76.51 + 3.294$$

$$= 4391.024 \$ \text{ per } 200\text{MW}$$

$$= 21.955 \$/\text{MW}$$

$$= 2.195 \times 10^{-2} \$/\text{KW}$$

$$= 1.46 \text{ Rs. } / \text{KW hr}$$

So, the complete ROTC has been evaluated for the 7th bus of the 7-Bus system and it is found to be **2.195 x 10⁻² \$/KW**.

Similarly if many other distributions systems were connected to all the buses and their reliability data and customer damage functions were known, then the ROTC for the overall system can be evaluated.

The discussion of the results and analysis of the case studies undertaken in this chapter clearly demonstrates that the aims and the objective set out for this investigation have been achieved.

CHAPTER - 9

9.1 CONCLUSION

Cost calculation and resultant pricing is a societal decision, as it is the result of public policy mixed with engineering, economic and political considerations. By its very nature, cost allocation must serve individual as well as collective interests and therefore it demands regulatory prescription or approval, just like transmission siting. Similarly, regulators and other concerned parties need a DMF and ROTC methodology to achieve optimal pricing for reliability and congestion costing.

The main purpose of this research was to develop concepts and techniques in ROTC evaluation and calculation, for composite power systems, using the proposed MAPA. In this research the aim was to devise a DMF and a methodology that can be used to include reliability benefits and achieve optimal cost allocation on an equitable and practical basis and hence it could be utilised for socio-economically viable Transmission Pricing.

The objectives to achieve the above stated purpose were to investigate and estimate transmission costing that would reflect reliability benefits with an efficient congestion costing approach.

In this research study a DMF was developed and based on that methodology a suite of MATLAB programs have been written and implemented, in order to evaluate ROTC, which can be applicable to countries like India.

The transmission network in an Electrical Power System plays a major role in supplying the electrical power between major parts of any country and is also the biggest source of revenue collection for electrical service providers. Therefore the

ROTC system was developed to provide greater scope for strengthening and expanding the transmission network according to future demands.

From the literature survey it has been concluded that most of the research has focused on implementation of proposed methods and procedures to different parts of the system such as Generation, Transmission, Distribution or Supply. But the combined approach for the whole power system costing using congestion cost and reliability benefits is missing. Minghai Liu, Gross (2004) used PTDF to evaluate the sensitivity analysis of active power flows and suggested that it can also be used to set congestion prices. This suggestion has been followed, extended and enhanced to include the ROTC methodology for calculation of the transmission and congestion costing. As this research has been considered in the context of the Indian electricity supply industry all the methods used and developed were also verified using data from the Indian transmission network and its implications for that country are discussed with respect to its feasibility and requirements.

The study and development of the methodology was undertaken in four parts i.e. Load Flow Analysis, Transmission Costing, Congestion Costing and Reliability worth Evaluation Studies.

The results obtained in the research were compared with previously researched methods. The obtained values were compared with the present charged price in India, which are comparable, satisfactory and justify the obtained results.

The study of devised ROTC was conducted on four systems i.e. the 7-Bus system, IEEE 30-Bus system, Indian Utility 146-Bus system and a Small radial Distribution system, to check the versatility of the developed MATLAB program and for each

case the results obtained using different method proposed and previously researched were found to be satisfactory.

In chapter 4, to achieve the desired objective, N-R method was used for Load Flow Analysis as it has the advantage of more accuracy and it does not diverge for poorly conditioned problems. It has been found to be a practical and efficient method for Load Flow Analysis. The main objective of undertaking a Load Flow analysis is to provide detailed information on the state of the power system, that is; power injected at every bus from the generators, the voltage and phase angle at all the buses and also the line flow and losses in the transmission lines. This information helps the designer to do further analysis for Congestion Costing, Transmission Costing and Reliability Analysis. It also helps the operator to operate the system smoothly and indicates if there is any disturbance in the power system network.

In chapter 5, Transmission Costing (TC) was undertaken using different approaches of the MW mile method. These methods were compared with each other and also with the proposed application of PTDF method for justification of the obtained results. After comparing Absolute MW Mile method with the proposed application of PTDF method it has been conclude that the proposed application of PTDF method gives similar results and can be used to calculate the embedded cost of the transmission system and it is considered to be justified and acceptable. After comparing the proposed application of PTDF method with Bialek's method it can be inferred that revenue collection using the proposed application of PTDF method is higher than Bialek's method. So the proposed application of PTDF method is useful for increased revenue generation to help future development and expansion in order to provide a more reliable system.

The proposed application of PTDF method takes into account all the positive and negative contributions of generators but Bialek's method considers only the positive contribution and other contributions are neglected.

It is suggested that as the proposed application of PTDF method gives the complete cost of transmission (without Reserve Capacity) and therefore it can be used in the Indian transmission pricing schemes, as it is not too complicated to implement and can be used along with other pricing methods, making it a hybrid methodology. Also the revenue collection is sufficient for the future growth and development of the Indian transmission network.

In chapter 6 Congestion Costing (CC) is estimated using the proposed application of PTDF method which uses other distribution factors to calculate the generator and load contribution to line flow; similarly Bialek's method is used to determine the same. The evaluated load and generators contributions using both the methods are used to further determine Transmission Costing. When the results of both methods were compared they were found to be similar and thus the proposed PTDF method was justified.

In chapter-7 Reliability Worth has been evaluated using two MC-VRT methods. In the process of calculating the reliability indices, required to find the worth of reliability, different approaches of the Monte Carlo simulation method were used, either to compare or to determine the results. Two VRT methods were used to find EENS at each load and for the complete system of all the three cases i.e. 7-Bus, 30-Bus and 146 Bus systems. Also both the methods are compared according to their speed of simulation and also for their accuracy in terms of coefficient of variance. A time sequential MC method was used to find the customer damage cost in terms of

the ECOST index. EENS for 7 Bus and ECOST for 7 Bus were used to find the IEAR index, which is actually the reliability worth for that bus in a 7-Bus system.

The results from each investigation suggest that the obtained transmission costing is the Complete/Optimal Transmission Costing that can be used to evaluate the overall pricing in the transmission System, as it includes the congestion and reliability components in it, which are the present requirements for efficiency and reliability of Transmission System Networks.

This investigation and evaluation has shown the importance of Congestion, Transmission and Reliability evaluation in Power System. Also it has shown the advantage and efficiency of the proposed application of PTDF method in comparison to other methods used for evaluation of ROTC.

This study brings together the complete analysis of transmission Costing including congestion and reliability of power systems, which can be used in any big networks for ROTC by utilizing the practical data of their particular transmission network in the developed MATLAB program.

Many software programs have been developed for power system analysis but in the developed MATLAB program researchers can modify and use the programming as per their requirements.

Finally the investigations have shown that a combination of methods is a common practice, reflecting the diversity of priorities. International practice with regard to cost allocation shows a pattern of “mixing and matching” elements of the various methods for allocating transmission costs. Most ISOs and RTOs in US, Europe and the rest of the world use this hybrid ‘mix and match’ approach, spreading some costs over peak MW to load while other costs are allocated using flow-based methods.

Internationally, there is a willingness to “mix and match” different cost allocation methods as well. Reasonable arguments support all of these methods.

Our most important conclusion to date is the stakeholders should consider mutually accepted priorities, such as the type of benefits and practical considerations when determining ROTC allocation. A DMF and methodology has been provided for stakeholders who place a stronger emphasis on grid reliability, which benefits everyone, or the fact that all users benefit from reduced losses with new transmission facilities, that can be easily understood and administered.

9.2 FUTURE WORK AND RECOMMENDATIONS

To expand upon the findings in this thesis further research work should be conducted investigating the complete ROTC considering the Reactive Components of Power as well.

The MATLAB program developed can be modified to be used for other Incremental and Embedded transmission pricing method that are not mentioned in this research work for Transmission Costing, Congestion Costing and Reliability worth Evaluation.

The Customer Survey Data for the present scenario can be used for more justified results, as different countries consumers have different willingness to pay for power losses in terms of hours of the day.

Fuzzy Loads or probabilistic load flow can be used for varying load demand to make the investigation more realistic. In the Planning process, forecasting is a complex task and there is a need for a tool to deal with the uncertainty rather than probability. The probabilistic approach can not model every type of uncertainty in power system

reliability. Considering fuzzy events the full load and reliability scenarios can be analysed at one time avoiding having to run simulations for each section of power system. The fuzzy sets more accurately represent the operational constraints of the power system, so that can be introduced in the developed programming for more accurate decision making for the ROTC.

Artificial Neural Networks (ANN) or Genetic Algorithms (GA) can be utilized to make the MATLAB program more accurate and faster. Genetic Algorithms provide near optimal or optimal solution for computationally intensive problems.

Genetic algorithm, ANN and Fuzzy Logic can be applied to long term energy forecasting by constructing models on relative information, such as climate and previous load demand data, so as to get desired form of accuracy. A combination of GA, ANN and other hybrid optimization technique can also be used to forecast the future load requirements.

Finally it is believed that the developed MATLAB program and methodologies will help researchers to carry on further investigations in Power System Analysis to achieve efficiency and reliability in Power Systems.

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APPENDIX

APPENDIX-A

A.1 BUS-DATA FOR 7- BUS SYSTEM

Table A.1: Generator Data for the 7-Bus System

Generator Data for the 7-Bus System					
Gen No.	P (Min)	P (Max)	Generator Cost Coefficients		
			a (\$/MWh ²)	b (\$/MWh)	c (\$/h)
GEN 1	10	400	0.002	8.5	300
GEN 2	10	500	0.0014	9.48	420
GEN 4	10	200	0.0013	7.29	253
GEN 6	10	500	0.0013	9.22	380
GEN 7	10	600	0.0019	9.28	380

Source: (Gnanadass 2015)

Table A.2: Bus Data for IEEE 7-Bus Transmission System

Bus	Type	Vsp	theta	PGi	QGi	PLi	QLi	Qmin	Qmax
1	1	1.05	0	180	0	0	0	0	0;
2	2	1.05	0	138	0	80	0	0	0;
3	3	1.07	0	0	0	110	0	0	0;
4	2	1.0	0	100	0	40	0	0	0;
5	3	1.0	0	0	0	130	0	0	0;
6	2	1.0	0	220	0	200	0	0	0;
7	2	1.0	0	125	0	200	0	0	0;]

Table A.3: Line Data for IEEE 7-Bus Transmission System

From Bus	To Bus	R	X	B/2	Tap Set	Status	line Limit	Line Length	Cost of Power
1	2	0.01	0.06	0.06	1	1	135	100	1000;
1	3	0.04	0.24	0.05	1	1	58	100	1000;
2	3	0.03	0.18	0.04	1	1	55	100	1000;
2	4	0.03	0.18	0.04	1	1	45	100	1000;
2	5	0.02	0.12	0.03	1	1	200	100	1000;
2	6	0.01	0.06	0.05	1	1	130	100	1000;
3	4	0.005	0.03	0.02	1	1	40	100	1000;

4	5	0.04	0.24	0.05	1	1	44	100	1000;
7	5	0.01	0.06	0.04	1	1	100	100	1000;
6	7	0.04	0.24	0.05	1	1	85	100	1000;]

APPENDIX-B

B.1 BUS-DATA FOR IEEE 30-BUS SYSTEM

Table B.1: Generator Data for the IEEE 30-Bus System

Generator Data for the 30-Bus System					
Gen No.	P (Min)	P (Max)	Generator Cost Coefficients		
			a (\$/MWh ²)	b (\$/MWh)	c (\$/h)
GEN 1	50	200	0.00375	2	0
GEN 2	20	80	0.0175	1.75	0
GEN 13	15	50	0.0625	1	0
GEN 22	10	35	0.00834	3.25	0
GEN 23	10	30	0.025	3	0
GEN 27	12	40	0.025	3	0

Source: (Gnanadass 2015)

Table B.2: Bus Data for IEEE 30-Bus Transmission System

Bus	Type	Vsp	theta	PGi	QGi	PLi	QLi	Qmin	Qmax
1	1	1.06	0	23.54	0	0	0	0	0;
2	2	1.043	0	60.97	50.0	21.7	12.7	-40	50;
3	3	1.0	0	0	0	2.4	1.2	0	0;
4	3	1.0	0	0	0	7.6	1.6	0	0;
5	2	1.01	0	0	37.0	0.0	19.0	-40	40;
6	3	1.0	0	0	0	0.0	0.0	0	0;
7	3	1.0	0	0	0	22.8	10.9	0	0;
8	2	1.01	0	0	37.3	30.0	30.0	-10	40;
9	3	1.0	0	0	0	0.0	0.0	0	0;
10	3	1.0	0	0	0	25.8	2.0	0	0;
11	2	1.082	0	0	16.2	0.01	0.0	-6	24;
12	3	1.0	0	0	0	11.2	7.5	0	0;
13	2	1.071	0	37	44.7	0.0	0.0	-6	24;
14	3	1.0	0	0	0	6.2	1.6	0	0;

15	3	1.0	0	0	0	8.2	2.5	0	0;
16	3	1.0	0	0	0	3.5	1.8	0	0;
17	3	1.0	0	0	0	40.0	5.8	0	0;
18	3	1.0	0	0	0	3.2	0.9	0	0;
19	3	1.0	0	0	0	9.5	3.4	0	0;
20	3	1.0	0	0	0	2.2	0.7	0	0;
21	3	1.0	0	0	0	17.5	11.2	0	0;
22	3	1.0	0	30	0	0.0	0.0	0	0;
23	3	1.0	0	19.2	0	3.2	1.6	0	0;
24	3	1.0	0	0	0	8.7	6.7	0	0;
25	3	1.0	0	0	0	0.0	0.0	0	0;
26	3	1.0	0	0	0	3.5	2.3	0	0;
27	3	1.0	0	26.91	0	0.0	0.0	0	0;
28	3	1.0	0	0	0	0.0	0.0	0	0;
29	3	1.0	0	0	0	2.4	0.9	0	0;
30	3	1.0	0	0	0	10.6	1.9	0	0]

Table B.3: Line Data for IEEE 30-Bus Transmission System

From Bus	To Bus	R	X	B/2	Tap Set	Status	line Limit	Line Length	Cost of Power
1	2	0.0192	0.0575	0.0264	1	1	130	100	1000;
1	3	0.0452	0.1852	0.0204	1	1	130	100	1000;
2	4	0.0570	0.1737	0.01840	1	1	65	100	1000;
3	4	0.0132	0.0379	0.00420	1	1	130	100	1000;
2	5	0.0472	0.1983	0.02090	1	1	130	100	1000;
2	6	0.0581	0.1763	0.01870	1	1	65	100	1000;
4	6	0.0119	0.0414	0.00450	1	1	90	100	1000;
5	7	0.0460	0.1160	0.01020	1	1	70	100	1000;
6	7	0.0267	0.0820	0.00850	1	1	130	100	1000;
6	8	0.0120	0.0420	0.00450	1	1	32	100	1000;
6	9	0.0	0.2080	0.00	0.978	1	65	100	1000;
6	10	0.0	0.5560	0.00	0.969	1	32	100	1000;
9	11	0.0	0.2080	0.00	1	1	65	100	1000;
9	10	0.0	0.1100	0.00	1	1	65	100	1000;
4	12	0.0	0.2560	0.00	1	1	65	100	1000;
12	13	0.0	0.1400	0.0	1	1	65	100	1000;
12	14	0.1231	0.2559	0.00	1	1	32	100	1000;
12	15	0.0662	0.1304	0.00	1	1	32	100	1000;
12	16	0.0945	0.1987	0.00	1	1	32	100	1000;
14	15	0.2210	0.1997	0.0	1	1	16	100	1000;

16	17	0.0824	0.1923	0.00	1	1	16	100	1000;
15	18	0.1073	0.2185	0.00	1	1	16	100	1000;
18	19	0.0639	0.1292	0.00	1	1	16	100	1000;
19	20	0.0340	0.0680	0.00	1	1	32	100	1000;
10	20	0.0936	0.2090	0.00	1	1	32	100	1000;
10	17	0.0324	0.0845	0.00	1	1	32	100	1000;
10	21	0.0348	0.0749	0.00	1	1	32	100	1000;
10	22	0.0727	0.1499	0.00	1	1	32	100	1000;
21	22	0.0116	0.0236	0.00	1	1	32	100	1000;
15	23	0.1000	0.2020	0.00	1	1	16	100	1000;
22	24	0.1150	0.1790	0.00	1	1	16	100	1000;
23	24	0.1320	0.2700	0.00	1	1	16	100	1000;
24	25	0.1885	0.3292	0.00	1	1	16	100	1000;
25	26	0.2544	0.3800	0.00	1	1	16	100	1000;
25	27	0.1093	0.2087	0.00	1	1	16	100	1000;
28	27	0.0000	0.3960	0.00	0.968	1	65	100	1000;
27	29	0.2198	0.4153	0.00	1	1	16	100	1000;
27	30	0.3202	0.6027	0.00	1	1	16	100	1000;
29	30	0.2399	0.4533	0.00	1	1	16	100	1000;
8	28	0.0636	0.200	0.0214	1	1	32	100	1000;
6	28	0.0169	0.0599	0.065	1	1	32	100	1000;

APPENDIX-C

C.1 BUS-DATA FOR INDIAN UTILITY 146-BUS SYSTEM

Table C.1: Generator Data for the Indian Utility 146-Bus System

Generator Data for the 146-Bus System					
Gen No.	P (Min)	P (Max)	Generator Cost Coefficients		
			a (\$/MWh ²)	b (\$/MWh)	c (\$/h)
GEN 1	0	300	0.0021	8.8	285
GEN 28	0	100	0.0048	7.9	190
GEN 29	100	500	0.0014	9.48	420
GEN 34	0	100	0.0048	7.9	190
GEN 35	0	100	0.0048	7.9	190
GEN 36	0	200	0.0013	7.29	253
GEN 37	0	100	0.0048	7.9	190
GEN 38	0	100	0.0048	7.9	190
GEN 39	0	100	0.0048	7.9	190
GEN 44	0	100	0.0048	7.9	190
GEN 47	50	360	0.002	8.5	300
GEN 49	60	360	0.002	8.5	300
GEN 58	0	200	0.0013	7.29	253
GEN 60	0	200	0.0013	7.29	253
GEN 61	0	100	0.0048	7.9	190
GEN 62	0	100	0.0048	7.9	190
GEN 63	0	200	0.0013	7.29	253
GEN 75	0	200	0.0013	7.29	253
GEN 79	0	100	0.0048	7.9	190
GEN 80	0	100	0.0048	7.9	190
GEN 81	50	500	0.0014	9.48	420
GEN 83	0	100	0.0048	7.9	190
GEN 88	0	100	0.0048	7.9	190
GEN 89	0	100	0.0048	7.9	190

Source: (Park, Kim et al. 1993)

Table C.2: Bus Data for Indian Utility 146-Bus Transmission System

Bus	Type	Vsp		theta		PGi		QGi		PLi		QLi		Qmin		Qmax	
1	1	1.06		0		280		100		163		73		62		248;	
2	3	1.1		0		0		0		86		79		0		0;	
3	3	1.1		0		0		0		40		10		0		0;	
4	3	1.1		0		0		0		67		50		0		0;	
5	3	1.1		0		0		0		1		0		0		0;	
6	3	1.1		0		0		0		149		90		0		0;	

										Cont...							
Bus	Type	Vsp		theta		PGi		QGi		PLi		QLi		Qmin		Qmax	
7	3	1.1		0		0		0		10		0		0		0;	
8	3	1.1		0		0		0		44		34		0		0;	
9	3	1.1		0		0		0		0		0		0		0;	
10	3	1.1		0		0		0		0		0		0		0;	
11	3	1.1		0		0		0		0		0		0		0;	
12	3	1.1		0		0		0		130		70		0		0;	
13	3	1.1		0		0		0		121		46		0		0;	
14	3	1.1		0		0		0		0		0		0		0;	
15	3	1.1		0		0		0		109		78		0		0;	
16	3	1.1		0		0		0		109		18		0		0;	
17	3	1.1		0		0		0		70		56		0		0;	
18	3	1.1		0		0		0		125		62		0		0;	
19	3	1.1		0		0		0		40		10		0		0;	
20	3	1.1		0		0		0		0		0		0		0;	
21	3	1.1		0		0		0		0		0		0		0;	
22	3	1.1		0		0		0		161		93		0		0;	
23	3	1.1		0		0		0		0		0		0		0;	
24	3	1.1		0		0		0		132		46		0		0;	
25	3	1.1		0		0		0		0		0		0		0;	
26	3	1.1		0		0		0		0		0		0		0;	
27	3	1.1		0		0		0		95		14		0		0;	
28	2	1.1		0		300		40		0		0		0		50;	
29	2	1.1		0		300		300		0		0		100		420;	
30	3	1.1		0		0		0		74		44		0		0;	
31	3	1.1		0		0		0		81		70		0		0;	
32	3	1.1		0		0		0		0		0		0		0;	
33	3	1.1		0		0		0		22		6		0		0;	
34	2	1.1		0		10		30		0		0		0		50;	

										Cont...							
Bus	Type	Vsp		theta		PGi		QGi		PLi		QLi		Qmin		Qmax	
35	2	1.1		0		90		40		0		0		10		50;	
36	2	1.1		0		190		80		17		12		25		100;	
37	2	1.1		0		90		40		10		3		0		50;	
38	2	1.1		0		90		40		42		9		0		50;	
39	2	1.1		0		90		40		60		23		0		50;	
40	3	1.1		0		0		0		46		25		0		0;	
41	3	1.1		0		0		0		0		0		0		0;	
42	3	1.1		0		0		0		0		0		0		0;	
43	3	1.1		0		0		0		0		0		0		0;	
44	2	1.1		0		90		40		0		0		0		50;	
45	3	1.1		0		0		0		94		29		0		0;	
46	3	1.1		0		0		0		48		32		0		0;	
47	2	1.1		0		280		80		0		0		0		150;	
48	3	1.1		0		0		0		248		78		0		0;	
49	2	1.1		0		330		150		130		93		50		240;	
50	3	1.1		0		0		0		0		0		0		0;	
51	3	1.1		0		0		0		66		0		0		0;	
52	3	1.1		0		0		0		124		44		0		0;	
53	3	1.1		0		0		0		93		23		0		0;	
54	3	1.1		0		0		0		0		0		0		0;	
55	3	1.1		0		0		0		0		0		0		0;	
56	3	1.1		0		0		0		0		0		0		0;	
57	3	1.1		0		0		0		0		0		0		0;	
58	2	1.1		0		180		80		60		46		0		100;	
59	3	1.1		0		0		0		0		0		0		0;	
60	2	1.1		0		190		90		210		0		0		100;	
61	2	1.1		0		90		40		0		0		0		50;	
62	2	1.1		0		90		40		0		0		0		60;	

										Cont...							
Bus	Type	Vsp		theta		PGi		QGi		PLi		QLi		Qmin		Qmax	
63	2	1.1		0		190		80		149		42		0		100;	
64	3	1.1		0		0		0		111		27		0		0;	
65	3	1.1		0		0		0		127		43		0		0;	
66	3	1.1		0		0		0		92		91		0		0;	
67	3	1.1		0		0		0		0		0		0		0;	
68	3	1.1		0		0		0		0		0		0		0;	
69	3	1.1		0		0		0		20		5		0		0;	
70	3	1.1		0		0		0		0		0		0		0;	
71	3	1.1		0		0		0		83		45		0		0;	
72	3	1.1		0		0		0		25		5		0		0;	
73	3	1.1		0		0		0		77		41		0		0;	
74	3	1.1		0		0		0		0		0		0		0;	
75	2	1.1		0		190		80		0		0		0		100;	
76	3	1.1		0		0		0		0		0		0		0;	
77	3	1.1		0		0		0		30		5		0		0;	
78	3	1.1		0		0		0		0		0		0		0;	
79	2	1.1		0		90		40		0		0		0		50;	
80	2	1.1		0		90		40		5		1		0		50;	
81	2	1.1		0		480		200		145		87		0		400;	
82	3	1.1		0		0		0		0		0		0		0;	
83	2	1.1		0		90		40		0		0		0		50;	
84	3	1.1		0		0		0		0		0		0		0;	
85	3	1.1		0		0		0		0		0		0		0;	
86	3	1.1		0		0		0		0		0		0		0;	
87	3	1.1		0		0		0		0		0		0		0;	
88	2	1.1		0		90		40		88		36		0		50;	
89	2	1.1		0		90		40		0		0		0		50;	
90	3	1.1		0		0		0		1		0		0		0;	

										Cont...							
Bus	Type	Vsp		theta		PGi		QGi		PLi		QLi		Qmin		Qmax	
91	3	1.1		0		0		0		0		0		0		0;	
92	3	1.1		0		0		0		1		0		0		0;	
93	3	1.1		0		0		0		1		0		0		0;	
94	3	1.1		0		0		0		1		0		0		0;	
95	3	1.1		0		0		0		0		0		0		0;	
96	3	1.1		0		0		0		0		0		0		0;	
97	3	1.1		0		0		0		1		0		0		0;	
98	3	1.1		0		0		0		1		0		0		0;	
99	3	1.1		0		0		0		1		0		0		0;	
100	3	1.1		0		0		0		1		0		0		0;	
101	3	1.1		0		0		0		1		0		0		0;	
102	3	1.1		0		0		0		1		0		0		0;	
103	3	1.1		0		0		0		1		0		0		0;	
104	3	1.1		0		0		0		1		0		0		0;	
105	3	1.1		0		0		0		1		0		0		0;	
106	3	1.1		0		0		0		1		0		0		0;	
107	3	1.1		0		0		0		1		0		0		0;	
108	3	1.1		0		0		0		1		0		0		0;	
109	3	1.1		0		0		0		1		0		0		0;	
110	3	1.1		0		0		0		1		0		0		0;	
111	3	1.1		0		0		0		1		0		0		0;	
112	3	1.1		0		0		0		1		0		0		0;	
113	3	1.1		0		0		0		1		0		0		0;	
114	3	1.1		0		0		0		1		0		0		0;	
115	3	1.1		0		0		0		1		0		0		0;	
116	3	1.1		0		0		0		1		0		0		0;	
117	3	1.1		0		0		0		1		0		0		0;	
118	3	1.1		0		0		0		1		0		0		0;	

										Cont...
Bus	Type	Vsp		theta		PGi		QGi		
PLi		QLi		Qmin		Qmax				
119	3	1.1		0		0		0		0;
120	3	1.1		0		0		1		0;
121	3	1.1		0		0		1		0;
122	3	1.1		0		0		1		0;
123	3	1.1		0		0		1		0;
124	3	1.1		0		0		1		0;
125	3	1.1		0		0		1		0;
126	3	1.1		0		0		1		0;
127	3	1.1		0		0		1		0;
128	3	1.1		0		0		1		0;
129	3	1.1		0		0		1		0;
130	3	1.1		0		0		1		0;
131	3	1.1		0		0		1		0;
132	3	1.1		0		0		1		0;
133	3	1.1		0		0		1		0;
134	3	1.1		0		0		1		0;
135	3	1.1		0		0		1		0;
136	3	1.1		0		0		1		0;
137	3	1.1		0		0		1		0;
138	3	1.1		0		0		1		0;
139	3	1.1		0		0		1		0;
140	3	1.1		0		0		1		0;
141	3	1.1		0		0		1		0;
142	3	1.1		0		0		1		0;
143	3	1.1		0		0		1		0;
144	3	1.1		0		0		1		0;
145	3	1.1		0		0		1		0;
146	3	1.1		0		0		1		0;1

Table C.3: Line Data for Indian Utility 146-Bus Transmission System

From Bus	To Bus	R pu	X pu	B/2 pu	X'mer TAP (a)
1	3	0.00305	0.01260	0.03401	1;
1	2	0.00716	0.02670	0.02340	1;
1	7	0.00548	0.01810	0.00390	1;
2	4	0.01569	0.04060	0.04540	1;
2	10	0.00229	0.00170	0.02080	1;
3	6	0.00411	0.02110	0.00950	1;
4	8	0.00168	0.00860	0.00295	1;
4	5	0.00289	0.01480	0.01373	1;
6	7	0.00381	0.01950	0.01800	1;
6	13	0.00411	0.02110	0.01950	1;
6	8	0.00520	0.02660	0.02460	1;
8	9	0.00411	0.02110	0.01950	1;
9	14	0.01315	0.06750	0.06237	1;
10	15	0.01537	0.07890	0.07292	1;
11	16	0.01950	0.09780	0.09030	1;
12	11	0.00686	0.03520	0.03250	1;
12	16	0.00716	0.03670	0.03390	1;
13	16	0.00575	0.01470	0.00309	1;
14	15	0.00030	0.00150	0.00578	1;
16	17	0.00049	0.00160	0.08612	1;
16	23	0.00575	0.01470	0.00309	1;
16	33	0.01460	0.07220	0.06670	1;
16	100	0.00343	0.01760	0.06504	1;
16	101	0.01850	0.09540	0.08810	1;
18	23	0.01371	0.02040	0.06704	96330;
18	19	0.00396	0.01030	0.02516	1;
18	98	0.00305	0.00560	0.01445	1;
18	99	0.00126	0.00450	0.00600	1;
19	20	0.01062	0.05550	0.01037	1;
20	21	0.00941	0.04820	0.04459	1;
21	22	0.01173	0.06020	0.05565	1;
22	102	0.00533	0.02730	0.02529	1;
22	103	0.02058	0.10570	0.06763	1;
23	24	0.02042	0.10480	0.09680	1;
24	104	0.01981	0.10170	0.03395	1;
24	25	0.01563	0.08030	0.04415	1;
24	30	0.00707	0.03631	0.01353	1;
25	26	0.00135	0.00690	0.02550	1;
26	28	0.00396	0.02030	0.01870	1;
26	30	0.01219	0.06260	0.05781	1;
28	27	0.01554	0.07990	0.07370	1;
28	34	0.00335	0.01710	0.01590	1;
29	27	0.00609	0.03130	0.02890	1;
30	31	0.00076	0.00390	0.01440	1;
30	33	0.00914	0.04690	0.04330	1;
30	92	0.02110	0.07278	0.03250	1;
30	105	0.00321	0.03522	0.03252	1;
32	24	0.00229	0.01174	0.02083	1;
32	31	0.00044	0.05361	0.05495	1;
32	106	0.00096	0.05525	0.00103	1;
32	107	0.01220	0.01022	0.03432	1;
34	35	0.01233	0.08922	0.03257	1;
35	36	0.00500	0.03600	0.05633	1;
36	37	0.00130	0.00184	0.00679	1;
36	90	0.00670	0.08609	0.07949	1;

Cont...

From Bus	To Bus	R pu	X pu	B/2 pu	X'mer TAP (a)
37	46	0.00780	0.09180	0.08477	1;
37	50	0.00590	0.05095	0.04705	1;
38	40	0.00010	0.03678	0.03397	1;
39	38	0.00300	0.01565	0.01445	1;
39	41	0.02200	0.11301	0.10435	1;
39	49	0.00390	0.02035	0.07516	1;
41	42	0.02090	0.10761	0.09937	1;
41	49	0.01820	0.09391	0.08672	1;
45	46	0.00100	0.00536	0.01980	1;
45	48	0.01670	0.08609	0.07949	1;
42	43	0.00880	0.04539	0.04191	1;
43	44	0.00920	0.04735	0.04372	1;
44	47	0.00240	0.01252	0.04625	1;
44	49	0.01490	0.07701	0.07111	1;
46	63	0.01380	0.07106	0.06562	1;
51	90	0.00330	0.01722	0.06359	1;
56	57	0.00410	0.02113	0.01951	1;
59	63	0.00670	0.03443	0.03180	1;
47	45	0.00180	0.00939	0.00800	1;
47	49	0.00150	0.00783	0.00700	1;
48	113	0.00250	0.01330	0.01220	1;
48	114	0.01120	0.05791	0.05340	1;
48	115	0.01130	0.05815	0.05360	1;
48	116	0.01410	0.07278	0.06721	1;
48	117	0.01190	0.06112	0.06644	1;
48	118	0.00400	0.02090	0.01930	1;
48	119	0.01250	0.06441	0.05948	1;
49	55	0.00060	0.00337	0.01242	1;
49	63	0.00670	0.03443	0.03180	1;
49	65	0.00360	0.01878	0.06938	1;
50	52	0.01270	0.07043	0.04504	1;
50	54	0.00690	0.04070	0.03758	1;
51	108	0.01160	0.07012	0.02475	1;
52	51	0.02210	0.06222	0.05345	1;
52	53	0.01154	0.03113	0.01479	1;
77	138	0.01410	0.02148	0.06223	1;
77	146	0.00680	0.01520	0.03252	1;
52	109	0.00220	0.00170	0.02085	1;
53	111	0.01040	0.05360	0.04650	1;
53	110	0.01070	0.03520	0.05102	1;
53	112	0.01990	0.00020	0.06438	1;
54	120	0.01730	0.01920	0.02258	1;
54	121	0.00700	0.03600	0.02320	1;
54	122	0.00030	0.00180	0.00670	1;
55	56	0.01670	0.02600	0.07940	1;
58	57	0.01780	0.01180	0.02470	1;
58	59	0.00990	0.05090	0.04700	1;
58	61	0.00710	0.03670	0.03390	1;
58	145	0.00300	0.01560	0.01440	1;
59	56	0.02200	0.21300	0.10430	1;
60	53	0.00390	0.00030	0.07510	1;
60	68	0.02090	0.11760	0.05690	1;
61	62	0.01820	0.09390	0.03670	1;
63	119	0.00100	0.00530	0.01980	0.98321;

						Cont...
From Bus	To Bus	R pu	X pu	B/2 pu	X'mer TAP (a)	
63	64	0.01670	0.02600	0.07949	1;	
63	75	0.00880	0.04530	0.04191	1;	
64	66	0.00920	0.04230	0.04372	1;	
64	77	0.00240	0.01350	0.04625	1;	
64	91	0.01490	0.07300	0.05111	1;	
64	126	0.01380	0.07000	0.06562	1;	
64	127	0.00330	0.01720	0.03359	1;	
65	75	0.00410	0.02110	0.01951	1;	
65	77	0.00670	0.03440	0.03180	1;	
65	79	0.00180	0.00930	0.00867	1;	
66	69	0.00150	0.00780	0.00723	1;	
66	128	0.00250	0.01330	0.01220	1;	
68	67	0.01120	0.05790	0.04530	1;	
69	71	0.01130	0.05810	0.05360	1;	
70	71	0.01410	0.07270	0.03720	1;	
70	129	0.01190	0.06110	0.05640	1;	
70	130	0.00400	0.02090	0.01930	1;	
71	67	0.01250	0.06440	0.02940	1;	
71	131	0.00060	0.00330	0.01242	1;	
71	132	0.00670	0.03440	0.03180	1;	
71	133	0.00360	0.01870	0.03938	1;	
71	134	0.01370	0.07040	0.05504	1;	
71	144	0.00790	0.04070	0.03758	1;	
72	73	0.01360	0.07012	0.07475	1;	
72	135	0.01210	0.06222	0.03745	1;	
72	136	0.01785	0.01342	0.04672	1;	
73	76	0.00317	0.01271	0.01320	1;	
73	82	0.00486	0.03523	0.05250	1;	
74	137	0.00129	0.01171	0.01080	1;	
75	64	0.00044	0.05367	0.04450	1;	
75	77	0.00076	0.05523	0.04100	1;	
76	74	0.00990	0.01027	0.03430	1;	
77	74	0.00737	0.03923	0.05625	1;	
77	78	0.01701	0.03600	0.02332	1;	
81	83	0.01036	0.00180	0.00670	1;	
91	123	0.00676	0.04600	0.07940	1;	
91	124	0.00787	0.01820	0.08470	1;	
91	125	0.01992	0.04090	0.02700	1;	
93	92	0.00716	0.02670	0.07397	1;	
93	94	0.00305	0.01560	0.00445	1;	
93	95	0.02200	0.01300	0.10435	1;	
95	96	0.00396	0.02030	0.09510	1;	
96	97	0.02095	0.00760	0.09930	1;	
77	82	0.01828	0.09390	0.04560	1;	
78	139	0.00104	0.00530	0.01980	1;	
78	140	0.01676	0.08600	0.07949	1;	
99	94	0.00884	0.04530	0.04191	1;	
78	81	0.00922	0.04730	0.04372	1;	
79	80	0.00244	0.01250	0.04265	1;	
79	81	0.01499	0.07700	0.07111	1;	
81	80	0.01383	0.07100	0.06560	1;	
81	88	0.01335	0.01720	0.06350	1;	
81	86	0.00411	0.02110	0.01951	1;	
81	141	0.01670	0.03440	0.03180	1;	
81	142	0.01183	0.00930	0.00867	1;	

Cont...						
From Bus	To Bus	R pu	X pu	B/2 pu	X'mer TAP (a)	
84	143	0.00052	0.00780	0.00723	1;	
92	90	0.00259	0.01330	0.01220	1;	
84	85	0.00127	0.05791	0.07340	1;	
85	86	0.02132	0.05815	0.05369	1;	
107	106	0.00417	0.07276	0.03721	1;	
85	87	0.00190	0.06113	0.05644	1;	
87	89	0.00407	0.02092	0.01930	1;	
89	88	0.00254	0.06446	0.00949	1;1;	

Table C.4: Power Injected, Voltage and Phase angle for Indian Utility 146-Bus System (Unconstrained case)

UNCONSTRAINED			POWER INJECTED		POWER GENERATED		LOAD	
BUS No.	VOLTAGE	ANGLE	MW	MVAR	MW	MVAR	MW	MVAR
1	1.06	0.00	148.65	542.40	311.65	615.40	163	73
2	1.01	-1.40	-74.47	-61.11	11.53	17.89	86	79
3	1.04	0.27	-26.80	7.77	13.20	17.77	40	10
4	0.98	-1.15	-55.33	-46.04	11.67	3.96	67	50
5	0.98	-1.16	-0.78	-0.18	0.22	-0.18	1	0
6	0.99	0.99	-101.15	-74.97	47.85	15.03	149	90
7	1.03	0.54	-0.89	12.85	9.11	12.85	10	0
8	0.98	-0.91	-36.62	-29.15	7.38	4.85	44	34
9	0.98	-1.43	-0.44	-0.12	-0.44	-0.12	0	0
10	1.01	-1.40	-4.87	0.63	-4.87	0.63	0	0
11	0.90	7.80	-0.10	-1.86	-0.10	-1.86	0	0
12	0.90	7.40	-91.56	-60.66	38.44	9.34	130	70
13	0.94	5.02	-61.20	-36.87	59.80	9.13	121	46
14	0.96	-3.06	-0.34	-0.22	-0.34	-0.22	0	0
15	0.96	-3.10	-87.08	-70.52	21.92	7.48	109	78
16	0.91	9.01	-56.70	57.86	52.30	75.86	109	18
17	0.91	8.97	-52.07	-50.49	17.93	5.51	70	56
18	0.82	8.93	-81.57	-19.23	43.43	42.77	125	62
19	0.81	8.11	-35.10	-9.16	4.90	0.84	40	10
20	0.75	4.24	-8.54	4.76	-8.54	4.76	0	0
21	0.71	0.90	-8.73	2.76	-8.73	2.76	0	0
22	0.64	-3.26	-64.51	-62.19	96.49	30.81	161	93
23	0.90	11.10	7.24	98.93	7.24	98.93	0	0
24	0.76	39.08	-130.13	159.11	1.87	205.11	132	46
25	0.49	61.93	-34.11	115.60	-34.11	115.60	0	0
26	0.46	63.90	-61.20	317.71	-61.20	317.71	0	0
27	-0.03	91.39	-83.51	56.27	11.49	70.27	95	14
28	0.24	77.41	83.28	486.03	83.28	486.03	0	0
29	-0.16	98.27	452.45	-49.29	452.45	-49.29	0	0
30	0.74	40.17	-68.72	146.21	5.28	190.21	74	44
31	0.74	39.99	-64.31	-64.16	16.69	5.84	81	70
32	0.75	39.23	0.18	-0.44	0.18	-0.44	0	0
33	0.85	27.60	-17.74	104.60	4.26	110.60	22	6
34	0.09	85.42	196.54	255.91	196.54	255.91	0	0
35	-0.59	122.58	87.68	345.02	87.68	345.02	0	0

36	-0.79	136.02	186.55	374.00	203.55	386.00	17	12
37	-0.80	136.90	134.02	-288.91	144.02	-285.91	10	3
38	-1.09	172.71	47.71	15.02	89.71	24.02	42	9
39	-1.09	172.69	30.16	-46.12	90.16	-23.12	60	23
40	-1.08	171.91	-45.70	-24.55	0.30	0.45	46	25
41	-1.11	172.21	0.12	0.61	0.12	0.61	0	0
42	-1.11	171.87	-0.07	0.33	-0.07	0.33	0	0
43	-1.10	171.80	-0.05	0.12	-0.05	0.12	0	0
44	-1.09	171.77	90.14	-63.04	90.14	-63.04	0	0
45	-1.07	167.72	-93.52	2.46	0.48	31.46	94	29
46	-1.06	166.22	-55.13	148.20	-7.13	180.20	48	32
47	-1.09	171.07	279.13	62.89	279.13	62.89	0	0
48	-1.05	164.78	-245.98	-67.01	2.02	10.99	248	78
49	-1.09	172.43	200.12	-149.41	330.12	-56.41	130	93
50	-0.79	135.08	0.69	2.67	0.69	2.67	0	0
51	-0.77	132.15	-71.85	1.77	-5.85	1.77	66	0
52	-0.75	132.78	-123.49	-42.35	0.51	1.65	124	44
53	-0.76	133.81	-92.07	-22.50	0.93	0.50	93	23
54	-0.79	134.96	0.02	0.16	0.02	0.16	0	0
55	-1.09	172.64	1.25	2.52	1.25	2.52	0	0
56	-1.10	174.72	3.20	4.06	3.20	4.06	0	0
57	-1.09	176.26	2.45	3.05	2.45	3.05	0	0
58	-1.10	177.85	123.64	-108.47	183.64	-62.47	60	46
59	-1.10	173.71	2.08	10.51	2.08	10.51	0	0
60	-0.76	133.97	-18.90	-61.24	191.10	-61.24	210	0
61	-1.10	181.10	91.60	-17.56	91.60	-17.56	0	0
62	-1.10	185.25	90.55	-18.61	90.55	-18.61	0	0
63	-1.09	170.81	45.27	-80.03	194.27	-38.03	149	42
64	-1.08	169.34	-117.24	6.89	-6.24	33.89	111	27
65	-1.11	173.32	-124.53	-27.54	2.47	15.46	127	43
66	-1.02	161.96	-91.50	-62.67	0.50	28.33	92	91
67	-0.95	148.22	7.93	14.70	7.93	14.70	0	0
68	-0.90	143.47	0.70	21.72	0.70	21.72	0	0
69	-1.01	160.88	-12.81	13.21	7.19	18.21	20	5
70	-0.98	153.19	0.10	-0.03	0.10	-0.03	0	0
71	-0.97	153.41	-67.28	-21.98	15.72	23.02	83	45
72	-1.09	167.87	-25.48	-4.50	-0.48	0.50	25	5
73	-1.09	168.93	-77.56	-40.38	-0.56	0.62	77	41
74	-1.10	169.75	0.06	1.00	0.06	1.00	0	0
75	-1.09	172.62	190.20	-77.71	190.20	-77.71	0	0
76	-1.09	169.36	0.11	0.81	0.11	0.81	0	0
77	-1.10	171.14	-28.69	14.43	1.31	19.43	30	5
78	-1.12	175.51	8.17	19.67	8.17	19.67	0	0
79	-1.10	175.27	99.13	222.58	99.13	222.58	0	0
80	-1.10	176.58	86.57	-22.30	91.57	-21.30	5	1
81	-1.10	181.06	469.95	1605.01	614.95	1692.01	145	87
82	-1.09	169.51	0.05	0.81	0.05	0.81	0	0
83	-1.08	189.49	213.68	-1707.1	213.68	-1707.1	0	0
84	-1.12	182.11	0.00	0.21	0.00	0.21	0	0
85	-1.12	182.14	0.06	0.80	0.06	0.80	0	0
86	-1.10	181.35	-0.32	0.44	-0.32	0.44	0	0
87	-1.10	183.14	0.57	0.47	0.57	0.47	0	0
88	-1.10	181.82	2.34	-50.57	90.34	-14.57	88	36

89	-1.10	183.54	90.22	-37.08	90.22	-37.08	0	0
90	-0.78	132.65	3.50	3.05	4.50	3.05	1	0
91	-1.12	168.84	0.35	1.05	0.35	1.05	0	0
92	-0.79	132.49	0.09	0.44	1.09	0.44	1	0
93	-0.80	132.12	0.72	-2.46	1.72	-2.46	1	0
94	-0.80	132.11	-1.18	0.07	-0.18	0.07	1	0
95	-0.79	131.37	-1.52	7.41	-1.52	7.41	0	0
96	-0.80	131.28	-0.37	1.32	-0.37	1.32	0	0
97	-0.80	131.14	-1.60	2.75	-0.60	2.75	1	0
98	0.82	8.93	-0.54	-0.44	0.46	-0.44	1	0
99	0.82	8.93	-0.56	-0.19	0.44	-0.19	1	0
100	0.91	9.00	-0.58	-1.10	0.42	-1.10	1	0
101	0.92	8.90	-0.53	-1.44	0.47	-1.44	1	0
102	0.64	-3.27	-0.32	-0.79	0.68	-0.79	1	0
103	0.64	-3.32	-0.29	-2.05	0.71	-2.05	1	0
104	0.76	39.00	-0.73	-0.44	0.27	-0.44	1	0
105	0.74	40.15	-0.75	-0.42	0.25	-0.42	1	0
106	0.75	39.20	-0.78	-0.01	0.22	-0.01	1	0
107	0.75	39.21	-0.68	-0.66	0.32	-0.66	1	0
108	-0.77	132.09	-1.11	0.15	-0.11	0.15	1	0
109	-0.75	132.78	-1.01	0.01	-0.01	0.01	1	0
110	-0.76	133.77	-0.98	-0.02	0.02	-0.02	1	0
111	-0.76	133.76	-0.99	-0.01	0.01	-0.01	1	0
112	-0.76	133.74	-0.99	-0.07	0.01	-0.07	1	0
113	-1.05	164.78	-0.98	-0.01	0.02	-0.01	1	0
114	-1.06	164.72	-0.98	-0.04	0.02	-0.04	1	0
115	-1.06	164.72	-0.98	-0.04	0.02	-0.04	1	0
116	-1.06	164.70	-0.98	-0.03	0.02	-0.03	1	0
117	-1.06	164.71	-0.98	-0.04	0.02	-0.04	1	0
118	-1.05	164.77	-0.98	-0.02	0.02	-0.02	1	0
119	-1.10	170.35	0.21	15.89	1.21	15.89	1	0
120	-0.79	134.93	-1.05	0.08	-0.05	0.08	1	0
121	-0.79	134.93	-1.04	0.05	-0.04	0.05	1	0
122	-0.79	134.96	-1.03	0.02	-0.03	0.02	1	0
123	-1.12	168.79	-1.13	0.42	-0.13	0.42	1	0
124	-1.12	168.79	-1.22	0.49	-0.22	0.49	1	0
125	-1.12	168.79	-1.12	0.17	-0.12	0.17	1	0
126	-1.09	169.26	-1.01	0.06	-0.01	0.06	1	0
127	-1.08	169.33	-1.01	0.02	-0.01	0.02	1	0
128	-1.02	161.95	-0.94	-0.05	0.06	-0.05	1	0
129	-0.98	153.12	-1.00	0.01	0.00	0.01	1	0
130	-0.98	153.17	-1.00	0.00	0.00	0.00	1	0
131	-0.97	153.41	-0.97	-0.03	0.03	-0.03	1	0
132	-0.97	153.38	-0.96	-0.06	0.04	-0.06	1	0
133	-0.97	153.39	-0.96	-0.07	0.04	-0.07	1	0
134	-0.97	153.33	-0.96	-0.08	0.04	-0.08	1	0
135	-1.10	167.82	-1.05	0.10	-0.05	0.10	1	0
136	-1.09	167.82	-1.07	0.18	-0.07	0.18	1	0
137	-1.10	169.74	-1.03	0.02	-0.03	0.02	1	0
138	-1.10	171.07	-1.04	0.09	-0.04	0.09	1	0
139	-1.12	175.51	-1.05	0.06	-0.05	0.06	1	0
140	-1.13	175.39	-1.09	0.29	-0.09	0.29	1	0
141	-1.10	181.02	-1.00	0.00	0.00	0.00	1	0

142	-1.10	181.05	-1.00	0.00	0.00	0.00	1	0
143	-1.12	182.11	-1.04	0.02	-0.04	0.02	1	0
144	-0.97	153.37	-0.96	-0.07	0.04	-0.07	1	0
145	-1.10	177.84	-1.00	0.00	0.00	0.00	1	0
146	-1.10	171.12	-1.03	0.04	-0.03	0.04	1	0

Table C.5: Line Flow and Line Loss for Indian Utility 146-Bus System
(Unconstrained case)

UNCONSTRAINED		LINE FLOW		FROM	TO	LINE FLOW		LINE LOSS		LINE LIMIT
FROM	TO	MW	MVAR			MW	MVAR	MW	MVAR	MW
1	3	8.62	205.47	3	1	-7.48	-200.73	1.15	4.74	90
1	2	141.17	161.54	2	1	-138.24	-150.60	2.93	10.94	200
1	7	-1.15	182.28	7	1	2.77	-176.93	1.62	5.35	90
2	4	12.94	60.71	4	2	-12.35	-59.18	0.59	1.53	60
2	10	50.83	37.92	10	2	-50.74	-37.86	0.09	0.07	90
3	6	-19.33	213.16	6	3	21.08	-204.15	1.76	9.02	90
4	8	-43.76	20.29	8	4	43.80	-20.09	0.04	0.21	130
4	5	0.78	-1.15	5	4	-0.78	1.15	0.00	0.00	32
6	7	4.99	-185.30	7	6	-3.66	192.09	1.33	6.80	90
6	13	-251.48	306.17	13	6	258.03	-272.56	6.55	33.61	500
6	8	124.26	15.36	8	6	-123.43	-11.13	0.83	4.23	200
8	9	43.02	6.61	9	8	-42.93	-6.20	0.08	0.41	90
9	14	42.49	13.93	14	9	-42.22	-12.52	0.27	1.41	90
10	15	45.87	48.02	15	10	-45.21	-44.59	0.67	3.42	90
11	16	-19.94	-8.61	16	11	20.06	9.16	0.11	0.56	90
12	11	-19.78	-16.66	11	12	19.84	16.95	0.06	0.29	90
12	16	-71.77	-38.58	16	12	72.35	41.57	0.58	2.99	130
13	16	-319.23	237.68	16	13	329.53	-211.35	10.30	26.33	500
14	15	41.88	18.64	15	14	-41.87	-18.61	0.01	0.03	90
16	17	52.10	43.22	17	16	-52.07	-43.13	0.03	0.09	130
16	23	-162.80	121.71	23	16	165.57	-114.61	2.78	7.10	300
16	33	-369.06	101.52	33	16	394.06	22.10	25.00	123.63	600
16	100	0.58	-4.47	100	16	-0.58	4.48	0.00	0.00	32
16	101	0.54	-6.15	101	16	-0.53	6.20	0.01	0.04	32
18	23	-269.06	-182.33	23	18	289.32	212.48	20.26	30.15	500
18	19	124.59	79.69	19	18	-123.33	-76.42	1.26	3.27	300
18	98	0.54	-0.56	98	18	-0.54	0.56	0.00	0.00	32
18	99	0.56	-0.23	99	18	-0.56	0.23	0.00	0.00	32
19	20	88.23	69.61	20	19	-86.20	-59.03	2.02	10.58	200
20	21	77.66	66.93	21	20	-75.94	-58.08	1.73	8.85	200
21	22	67.20	65.83	22	21	-65.12	-55.13	2.08	10.70	200
22	102	0.32	-0.24	102	22	-0.32	0.24	0.00	0.00	32
22	103	0.29	-0.73	103	22	-0.29	0.73	0.00	0.00	32
23	24	-375.05	123.12	24	23	412.93	71.33	37.89	194.45	600
24	104	0.73	-2.78	104	24	-0.73	2.79	0.00	0.01	32
24	25	-474.86	98.74	25	24	513.71	100.85	38.85	199.59	600
24	30	-47.00	14.42	30	24	47.18	-13.49	0.18	0.93	90
25	26	-547.82	22.43	26	25	551.50	-3.62	3.68	18.81	650
26	28	-1300.8	184.47	28	26	1362.08	129.61	61.27	314.07	1400
26	30	688.11	148.25	30	26	-633.97	129.76	54.13	278.00	900

28	27	-341.78	116.85	27	28	358.53	-30.70	16.76	86.15	300
28	34	-937.02	252.67	34	28	963.09	-119.57	26.08	133.10	900
29	27	452.45	-45.79	27	29	-442.04	99.29	10.41	53.50	500
30	31	87.63	48.51	31	30	-87.54	-48.09	0.08	0.41	130
30	33	429.69	-0.67	33	30	-411.79	92.50	17.90	91.83	600
30	105	0.75	-2.65	105	30	-0.75	2.66	0.00	0.00	32
32	24	21.94	2.85	24	32	-21.93	-2.78	0.01	0.06	90
32	31	-23.23	9.92	31	32	23.23	-9.56	0.00	0.36	90
32	106	0.78	-0.08	106	32	-0.78	0.08	0.00	0.00	32
32	107	0.68	-2.59	107	32	-0.68	2.59	0.00	0.00	32
34	35	-766.55	381.35	35	34	841.25	159.15	74.70	540.50	900
35	36	-753.56	196.63	36	35	778.63	-16.18	25.06	180.45	900
36	37	-673.02	483.33	37	36	680.40	-472.89	7.38	10.44	900
36	90	80.94	-75.89	90	36	-80.26	84.65	0.68	8.76	90
37	46	-619.08	233.10	46	37	647.29	98.90	28.21	331.99	900
37	50	72.71	-32.35	50	37	-72.40	35.02	0.31	2.67	90
38	40	45.71	21.26	40	38	-45.70	-20.49	0.00	0.77	90
39	38	-2.00	0.38	38	39	2.00	-0.38	0.00	0.00	32
39	41	5.59	-18.01	41	39	-5.52	18.34	0.06	0.33	32
39	49	26.57	-5.03	49	39	-26.54	5.15	0.02	0.12	90
41	42	6.48	-2.37	42	41	-6.47	2.41	0.01	0.04	32
41	49	-0.83	20.90	49	41	0.90	-20.57	0.06	0.33	32
45	46	572.98	-40.65	46	45	-570.21	55.48	2.77	14.84	900
45	48	68.81	-10.75	48	45	-68.13	14.26	0.68	3.50	90
42	43	6.40	15.59	43	42	-6.38	-15.49	0.02	0.10	32
43	44	6.33	26.20	44	43	-6.28	-25.92	0.05	0.28	32
44	47	113.69	-21.08	47	44	-113.43	22.46	0.27	1.38	200
44	49	-17.28	3.45	49	44	17.31	-3.25	0.04	0.20	32
46	63	-132.21	13.99	63	46	134.27	-3.40	2.06	10.59	200
51	90	-77.70	-53.32	90	51	77.93	54.49	0.22	1.16	90
56	57	-133.43	96.36	57	56	134.35	-91.65	0.91	4.71	200
59	63	175.13	-16.33	63	59	-173.43	25.07	1.70	8.74	200
47	45	743.54	-23.70	45	47	-735.31	66.65	8.23	42.95	900
47	49	-350.99	71.54	49	47	352.58	-63.24	1.59	8.30	500
48	113	0.98	-1.44	113	48	-0.98	1.44	0.00	0.00	32
48	114	0.98	-6.34	114	48	-0.98	6.36	0.00	0.02	32
48	115	0.98	-6.36	115	48	-0.98	6.38	0.00	0.02	32
48	116	0.98	-8.01	116	48	-0.98	8.05	0.01	0.04	32
48	117	0.98	-7.90	117	48	-0.98	7.94	0.01	0.03	32
48	118	0.98	-2.28	118	48	-0.98	2.28	0.00	0.00	32
48	119	-183.75	0.02	119	48	187.29	18.25	3.54	18.27	200
49	55	-125.12	56.85	55	49	125.21	-56.33	0.09	0.53	200
49	63	95.65	-17.22	63	49	-95.13	19.91	0.52	2.69	130
49	65	-114.66	-64.35	65	49	115.17	67.03	0.51	2.68	200
50	52	69.95	1.70	52	50	-69.45	1.09	0.50	2.79	90
50	54	3.13	-18.02	54	50	-3.11	18.13	0.02	0.11	32
51	108	1.11	-3.40	108	51	-1.11	3.41	0.00	0.01	32
52	51	-3.74	-74.29	51	52	4.74	77.12	1.00	2.83	32
52	53	-51.31	49.74	53	52	51.79	-48.43	0.48	1.31	90
77	138	1.05	-7.75	138	77	-1.04	7.76	0.01	0.01	32
77	146	1.03	-4.04	146	77	-1.03	4.04	0.00	0.00	32
52	109	1.01	-2.55	109	52	-1.01	2.55	0.00	0.00	32
53	111	0.99	-5.57	111	53	-0.99	5.59	0.00	0.01	32

53	112	1.00	-7.64	112	53	-0.99	7.64	0.01	0.00	32
54	120	1.05	-2.90	120	54	-1.05	2.90	0.00	0.00	32
54	121	1.04	-2.96	121	54	-1.04	2.96	0.00	0.00	32
54	122	1.03	-0.85	122	54	-1.03	0.85	0.00	0.00	32
55	56	-123.96	69.94	56	55	126.77	-65.58	2.80	4.36	200
58	57	136.01	-97.21	57	58	-131.90	99.94	4.11	2.73	200
58	59	165.55	-34.89	59	58	-163.21	46.93	2.34	12.04	200
58	61	-178.92	39.90	61	58	180.89	-29.71	1.97	10.19	200
58	145	1.00	-1.74	145	58	-1.00	1.74	0.00	0.00	32
59	56	-9.85	2.23	56	59	9.87	-2.05	0.02	0.18	32
60	53	147.73	-75.38	53	60	-146.84	75.45	0.89	0.07	300
60	68	-166.62	30.11	68	60	171.58	-2.24	4.95	27.86	200
61	62	-89.29	20.69	62	61	90.55	-14.17	1.26	6.52	130
63	119	115.11	-388.94	119	63	-113.78	396.03	1.34	7.09	200
63	64	79.02	-63.38	64	63	-77.60	65.58	1.42	2.20	90
63	75	-79.76	16.80	75	63	80.25	-14.28	0.49	2.52	130
64	66	365.51	31.84	66	64	-355.33	14.93	10.17	46.77	500
64	77	-281.55	10.98	77	64	283.12	-2.18	1.57	8.80	300
64	91	3.53	-56.61	91	64	-3.14	58.53	0.39	1.93	32
64	126	1.02	-8.09	126	64	-1.01	8.13	0.01	0.04	32
64	127	1.01	-4.11	127	64	-1.01	4.11	0.00	0.00	32
65	75	83.72	62.77	75	65	-83.36	-60.91	0.36	1.86	130
65	77	136.48	-3.85	77	65	-135.48	9.01	1.00	5.16	200
65	79	-384.07	254.41	79	65	387.24	-238.02	3.17	16.39	500
66	69	262.90	-69.03	69	66	-261.93	74.07	0.97	5.04	300
66	128	0.94	-1.35	128	66	-0.94	1.35	0.00	0.00	32
68	67	-170.88	36.66	67	68	173.63	-22.43	2.75	14.23	200
69	71	249.12	-53.89	71	69	-242.72	86.79	6.40	32.90	300
70	71	-1.90	22.74	71	70	1.96	-22.42	0.06	0.31	32
70	129	1.00	-6.83	129	70	-1.00	6.86	0.00	0.02	32
70	130	1.00	-2.32	130	70	-1.00	2.32	0.00	0.00	32
71	67	159.03	-80.82	67	71	-155.73	97.82	3.30	17.00	200
71	131	0.97	-1.43	131	71	-0.97	1.43	0.00	0.00	32
71	132	0.96	-3.68	132	71	-0.96	3.68	0.00	0.00	32
71	133	0.96	-4.55	133	71	-0.96	4.55	0.00	0.00	32
71	134	0.96	-6.40	134	71	-0.96	6.43	0.00	0.03	32
71	144	0.96	-4.35	144	71	-0.96	4.36	0.00	0.01	32
72	73	-27.61	26.27	73	72	27.77	-25.46	0.16	0.81	90
72	135	1.06	-4.80	135	72	-1.05	4.82	0.00	0.01	32
72	136	1.08	-6.04	136	72	-1.07	6.05	0.01	0.00	32
73	76	-69.78	6.28	76	73	69.91	-5.77	0.13	0.51	90
73	82	-35.54	-4.00	82	73	35.60	4.36	0.05	0.37	90
74	137	1.03	-1.36	137	74	-1.03	1.36	0.00	0.00	32
75	64	129.22	-4.22	64	75	-129.16	11.64	0.06	7.41	200
75	77	56.94	-17.31	77	75	-56.91	18.93	0.02	1.62	90
76	74	-69.80	12.42	74	76	70.21	-11.99	0.41	0.42	90
77	74	71.52	-25.07	74	77	-71.18	26.90	0.34	1.83	90
77	78	-228.75	74.70	78	77	236.77	-57.74	8.01	16.96	300
81	83	-169.30	1714.06	83	81	418.79	-1670.7	249.49	43.35	500
91	123	1.14	-10.78	123	91	-1.13	10.82	0.01	0.04	32
91	124	1.23	-11.52	124	91	-1.22	11.54	0.01	0.02	32
91	125	1.12	-3.68	125	91	-1.12	3.69	0.00	0.00	32

93	92	-5.10	106.55	92	93	5.67	-104.41	0.57	2.13	32
93	94	1.18	-0.70	94	93	-1.18	0.70	0.00	0.00	32
93	95	4.64	-82.29	95	93	-3.59	82.91	1.05	0.62	32
95	96	2.07	-46.71	96	95	-2.01	47.02	0.06	0.31	32
96	97	1.64	-17.28	97	96	-1.60	17.29	0.04	0.02	32
77	82	35.74	-7.51	82	77	-35.54	8.53	0.20	1.02	90
78	139	1.05	-2.55	139	78	-1.05	2.55	0.00	0.00	32
78	140	1.10	-10.38	140	78	-1.09	10.45	0.01	0.07	32
78	81	-230.75	111.31	81	78	235.55	-86.68	4.80	24.63	300
79	80	-212.98	44.11	80	79	213.93	-39.22	0.95	4.89	300
79	81	-151.36	37.50	81	79	154.37	-22.02	3.01	15.47	200
81	80	129.32	-19.98	80	81	-127.36	30.02	1.96	10.05	200
81	88	-57.91	45.56	88	81	58.51	-44.79	0.60	0.77	90
81	86	-32.91	-19.73	86	81	32.96	19.99	0.05	0.26	90
81	141	1.00	-3.86	141	81	-1.00	3.86	0.00	0.00	32
81	142	1.00	-1.05	142	81	-1.00	1.05	0.00	0.00	32
84	143	1.04	-0.93	143	84	-1.04	0.93	0.00	0.00	32
92	90	-5.58	116.64	90	92	5.83	-115.32	0.26	1.33	32
84	85	-1.04	11.31	85	84	1.04	-11.25	0.00	0.06	90
85	86	33.49	11.20	86	85	-33.27	-10.62	0.21	0.58	90
85	87	-34.46	23.75	87	85	34.49	-22.90	0.03	0.86	90
87	89	-33.92	32.61	89	87	33.99	-32.23	0.07	0.38	90
89	88	56.23	-1.37	88	89	-56.17	3.06	0.07	1.69	90

APPENDIX-D

MATLAB CODES

D.1 MATLAB PROGRAM FOR Y-BUS

```
% Program to form Admittance And Impedance Matrix....
% with Transformer Tap setting..

function ybus = ybus71c() % ybus

linedata = linedata71c(); % Calling "linedata71c.m" for Line Data...
fb = linedata(:,1);      % From bus number...
tb = linedata(:,2);      % To bus number...
r = linedata(:,3);       % Resistance, R...
x = linedata(:,4);       % Reactance, X...
b = linedata(:,5);       % Ground Admittance, B/2...
a = linedata(:,6);       % Tap setting value..
z = r + i*x;             % Z matrix...
y = 1./z;                % To get inverse of each element...
b = i*b;                 % Make B imaginary...

nbus = max(max(fb),max(tb)); % no. of buses...
nbranch = length(fb);      % no. of branches...
ybus = zeros(nbus,nbus);   % Initialise yBus...

% Off Diagonal Elements Formation...
for k = 1:nbranch
    ybus(fb(k),tb(k)) = ybus(fb(k),tb(k))-y(k)/a(k);
    ybus(tb(k),fb(k)) = ybus(fb(k),tb(k));
end

% Diagonal Elements Formation....
for m = 1:nbus
    for n = 1:nbranch
        if fb(n) == m
            ybus(m,m) = ybus(m,m) + y(n)/(a(n)^2) + b(n);
        elseif tb(n) == m
            ybus(m,m) = ybus(m,m) + y(n) + b(n);
        end
    end
end
ybus;
zbus = inv(ybus);
```

D.2 MATLAB PROGRAM NEWTON RAPHSON LOAD FLOW

```
% Program for Newton-Raphson Load Flow Analysis
% Bus number 1 is assumed to be slack bus..
clc();
clear();
Y = ybus71c(); % Get Y-Bus..
busdata = busdata71c(); % Get Bus Data..
baseMVA = 100; % Base MVA..
bus = busdata(:,1); % Bus Number..
type = busdata(:,2); % Type of Bus 1-Slack, 2-PV, 3-PQ..
V = busdata(:,3); % Specified Voltage..
del = busdata(:,4); % Voltage Angle..
Pg = busdata(:,5); % Active Power Generated PGi..
Qg = busdata(:,6); % Reactive Power Generated QGi..
Pl = busdata(:,7); % Active load PLi..
Ql = busdata(:,8); % Reactive load QLi..
Qmin = busdata(:,9); % Minimum Reactive Power Limit..
Qmax = busdata(:,10); % Maximum Reactive Power Limit..
nbus = max(bus); % To form no. of buses..
P = Pg - Pl; % Pi = PGi - PLi..
Q = Qg - Ql; % Qi = QGi - QLi..
P = P/baseMVA; % Converting to per.unit..
Q = Q/baseMVA;
Qmin = Qmin/baseMVA;
Qmax = Qmax/baseMVA;
Tol = 10; % Tolerance kept at high value.
Iter = 1; % starting Iterations
Psp = P;
Qsp = Q;
G = real(Y); % Conductance..
B = imag(Y); % Susceptance..
ref = find(type == 1); % Index of Reference Bus..
pv = find(type == 2 | type == 1); % Index of PV Buses..
pq = find(type == 3); % Index of PQ Buses..
npv = length(pv); % Number of PV buses..
npq = length(pq); % Number of PQ buses..

while (Tol > 1e-5) % Iteration starting..
    P = zeros(nbus,1);
    Q = zeros(nbus,1);
    % Active and Reactive power Calculation
    for i = 1:nbus
        for k = 1:nbus
            P(i) = P(i) + V(i)* V(k)*(G(i,k)*cos(del(i)-del(k)) +
                B(i,k)*sin(del(i)-del(k)));
            Q(i) = Q(i) + V(i)* V(k)*(G(i,k)*sin(del(i)-del(k)) -
                B(i,k)*cos(del(i)-del(k)));
        end
    end

    % Checking violations for Q-limit..
    if Iter <= 7 && Iter >= 2
        for n = 2:nbus
            if type(n) == 2
                if Q(n) < Qmin(n)

```

```

        V(n) = V(n) + 0.01;
    elseif Q(n) > Qmax(n)
        V(n) = V(n) - 0.01;
    end
end
end
end

% change Calculation from specified value
dPa = Psp-P;
dQa = Qsp-Q;
dQ = zeros(npq,1);
k = 1;
for i = 1:nbus
    if type(i) == 3
        dQ(k,1) = dQa(i);
        k = k+1;
    end
end
end
dP = dPa(2:nbus);
M = [dP; dQ]; % Mismatch Vector

% Forming Jacobian
% J1 - Derivative of Real Power Injections with Angles..
J1 = zeros(nbus-1,nbus-1);
for i = 1:(nbus-1)
    m = i+1;
    for k = 1:(nbus-1)
        n = k+1;
        if n == m
            for q = 1:nbus
                J1(i,k) = J1(i,k) + V(m)* V(q)*(-G(m,q)*sin(del(m)-del(q)) + B(m,q)*cos(del(m)-del(q)));
            end
            J1(i,k) = J1(i,k) - V(m)^2*B(m,m);
        else
            J1(i,k) = V(m)* V(n)*(G(m,n)*sin(del(m)-del(n)) - B(m,n)*cos(del(m)-del(n)));
        end
    end
end
end

% J2 - Derivative of Real Power Injections with V..
J2 = zeros(nbus-1,npq);
for i = 1:(nbus-1)
    m = i+1;
    for k = 1:npq
        n = pq(k);
        if n == m
            for q = 1:nbus
                J2(i,k) = J2(i,k) + V(q)*(G(m,q)*cos(del(m)-del(q)) + B(m,q)*sin(del(m)-del(q)));
            end
            J2(i,k) = J2(i,k) + V(m)*G(m,m);
        else
            J2(i,k) = V(m)*(G(m,n)*cos(del(m)-del(n)) + B(m,n)*sin(del(m)-del(n)));
        end
    end
end

```

```

        end
    end

    % J3 - Derivative of Reactive Power Injections with Angles..
    J3 = zeros(npq,nbus-1);
    for i = 1:npq
        m = pq(i);
        for k = 1:(nbus-1)
            n = k+1;
            if n == m
                for q = 1:nbus
                    J3(i,k) = J3(i,k) + V(m)* V(q)*(G(m,q)*cos(del(m)-
                    del(q)) + B(m,q)*sin(del(m)-del(q)));
                end
                J3(i,k) = J3(i,k) - V(m)^2*G(m,m);
            else
                J3(i,k) = V(m)* V(n)*(-G(m,n)*cos(del(m)-del(n)) -
                B(m,n)*sin(del(m)-del(n)));
            end
        end
    end

    % J4 - Derivative of Reactive Power Injections with V..
    J4 = zeros(npq,npq);
    for i = 1:npq
        m = pq(i);
        for k = 1:npq
            n = pq(k);
            if n == m
                for q = 1:nbus
                    J4(i,k) = J4(i,k) + V(q)*(G(m,q)*sin(del(m)-del(q)) -
                    B(m,q)*cos(del(m)-del(q)));
                end
                J4(i,k) = J4(i,k) - V(m)*B(m,m);
            else
                J4(i,k) = V(m)*(G(m,n)*sin(del(m)-del(n)) -
                B(m,n)*cos(del(m)-del(n)));
            end
        end
    end

    J = [J1 J2; J3 J4];      % Jacobian Matrix

    X = inv(J)*M;            % Correction Vector
    dTh = X(1:nbus-1);
    dV = X(nbus:end);
    del(2:nbus) = dTh + del(2:nbus);
    k = 1;
    for i = 2:nbus
        if type(i) == 3
            V(i) = dV(k) + V(i);
            k = k+1;
        end
    end
    Iter = Iter + 1;
    Tol = max(abs(M));
end
Iter = Iter - 1 % Total Number of Iterations..

```

```

V;
Del = 180/pi*del;
E1 = [V Del]; % Bus Voltages and angles..
disp('-----');
disp(' | Bus | V | Angle | ');
disp(' | No | pu | Degree | ');
disp('-----');
for m = 1:nbus
fprintf('%4g', m), fprintf(' %8.4f', V(m)), fprintf(' %8.4f',
Del(m)); fprintf('\n');
end
disp('-----');
for m= 1:nbus
V(m)=V(m)*cos(del(m))+j*V(m)*sin(del(m));
End

```

D.3 MATLAB PROGRAM FOR LINE FLOW AND POWER LOSSES USING N-R METHOD

```

%%-----
% Program for Bus Power Injections, Line & Power flows (p.u)...

linedata = linedata71c(); % Get line data's..
fb = linedata(:,1); % From bus number...
tb = linedata(:,2); % To bus number...
nl = length(fb); % No. of Branches..
b = linedata(:,5); % Total line charging Susceptance..
Pl = busdata(:,7); % PLi..
Ql = busdata(:,8); % QLi..
Tap = linedata(:,6); % Tap
LT = linedata(:,8); % Line limit
LN = linedata(:,9); %Line length
CP = linedata(:,10); %Cost of power
Iij = zeros(nbus,nbus); %Initializing Current
Sij = zeros(nbus,nbus); %Initializing Total power
Si = zeros(nbus,1);

% BUS CURRENT INJECTIONS..
I = Y*V;
Im = abs(I);
Ia = angle(I);

%LINE CURRENT FLOWS..
for m = 1:nl
p = fb(m); q = tb(m);
Iij(p,q) = -(V(p) - V(q))*Y(p,q); % Y(m,n) = -y(m,n)..
Iij(q,p) = -Iij(p,q);
end
Iij = sparse(Iij);
Iijm = abs(Iij);
Iija = angle(Iij);

% LINE POWER FLOWS..
for m = 1:nbus
for n = 1:nbus

```

```

        if m ~= n
            Sij(m,n) = V(m)*conj(Iij(m,n))*baseMVA;
        end
    end
end
Sij = sparse(Sij);
Plij = real(Sij);
Qij = imag(Sij);
disp('-----');

% LINE LOSSES..
Lij = zeros(nl,1);
for m = 1:nl
    p = fb(m); q = tb(m);
    Lij(m) = Sij(p,q) + Sij(q,p);
end
Lpij = real(Lij);
Lqij = imag(Lij);

% BUS POWER INJECTIONS..
for i = 1:nbus
    for k = 1:nbus
        Si(i) = Si(i) + conj(V(i))* V(k)*Y(i,k)*baseMVA;
    end
end
Pi = real(Si);
Qi = -imag(Si);
Pg = Pi+Pl;
Qg = Qi+Ql;

disp('#####');
disp('-----');
disp('                                Newton Raphson Load flow Analysis ');
disp('-----');
disp('| Bus | V | Angle | Injection | Generation | Load | ');
disp('| No | pu | Degree| MW | MVar | MW | Mvar |MW |MVar | ');
for m = 1:nbus
    disp('-----');
    fprintf('%3g',m); fprintf('%8.4f', V(m));fprintf('%8.4f',Del(m));
    fprintf(' %8.3f', Pi(m)); fprintf(' %8.3f', Qi(m));
    fprintf(' %8.3f', Pg(m)); fprintf(' %8.3f', Qg(m));
    fprintf(' %8.3f', Pl(m)); fprintf(' %8.3f', Ql(m));
    fprintf('\n');
end
disp('-----');
fprintf(' Total                               ');fprintf(' %8.3f', sum(Pi));
fprintf(' %8.3f', sum(Qi));
fprintf(' %8.3f', sum(Pi+Pl)); fprintf(' %8.3f', sum(Qi+Ql));
fprintf(' %8.3f', sum(Pl)); fprintf(' %8.3f', sum(Ql));
fprintf('\n');
disp('-----');
disp('#####');

disp('-----');
disp('                                Line Flow and Losses ');
disp('-----');
disp('|From|To | P | Q | From| To | P | Q | Line Loss | ');
disp('|Bus |Bus| MW | MVar| Bus | Bus| MW | MVar| MW | MVar | ');

```

```

for m = 1:nl
    p = fb(m); q = tb(m);
    disp('-----');
    fprintf('%4g', p); fprintf('%4g', q); fprintf(' %8.3f',
Plij(p,q)); fprintf(' %8.3f', Qij(p,q));
    fprintf(' %4g', q); fprintf('%4g', p); fprintf(' %8.3f',
Plij(q,p)); fprintf(' %8.3f', Qij(q,p));
    fprintf(' %8.3f', Lpij(m)); fprintf(' %8.3f', Lqij(m));
    fprintf('\n');
end
disp('-----');
fprintf(' Total Loss
');
fprintf(' %8.3f', sum(Lpij)); fprintf(' %8.3f', sum(Lqij));
fprintf('\n');
disp('-----');
disp('#####');
for m = 1:nl
    p = fb(m); q = tb(m);
    PLineForw(m) = Plij(p,q);
    QLineForw(m) = Qij(p,q);
    PLineReve(m) = Plij(q,p);
    QLineReve(m) = Qij(q,p);
end
PlineForwI=PLineForw';
QlineForwI=QLineForw';
PlineReveI=PLineReve';
QlineReveI=QLineReve';

```

D.4 MATLAB PROGRAM FOR PTDF CALCULATION

```

%-----PTDF CALCULATION-----

%% use reference bus for slack by default
if nargin < 4
    slack = type(1,:) == ref;
    slack = slack(1);
end

%% set the slack bus to be used to compute initial PTDF
slack = type(1,:) == ref;
slack = slack(1);
if length(slack) == 1
    slack_bus = slack;
else
    slack_bus = 1;      %% use bus 1 for temp slack bus
end
noref = (2:nbus)' ;    %% use bus 1 for voltage angle reference
noslack = find((1:nbus)' ~= slack_bus);

%% build connection matrix Cft = Cf - Ct for line and from - to
buses
Cf = sparse(1:nl, fb, ones(nl, 1), nl, nbus);      %% connection
matrix for line & from buses
i = [(1:nl)'; (1:nl)'] ;      %% double set of row indices
Cft = sparse(i, [fb;tb], [ones(nl, 1); -ones(nl, 1)], nl, nbus);
%% connection matrix

```

```

%% build Bf such that Bf * Va is the vector of real branch powers
injected
%% at each branch's "from" bus
tap = ones(nl, 1); % default tap ratio = 1
it = find(linedata(:, 6)); % indices of non-zero tap ratios
tap(it) = linedata(it, 6); % assign non-zero tap ratios
b = b ./ tap;
Bf = sparse(i, [fb; tb], [b; -b]); % = spdiags(b, 0, nl, nl) * Cft;

%% build Bbus
Bbus = Cft' * Bf;
%% compute PTDF for single slack_bus
H = zeros(nl-1, nbus);
Bf(:, noref);
Bbus(noslack, noref);
H = full (Bf(:, noref) / Bbus(noslack, noref))

%% distribute slack, if requested
if length(slack) ~= 1
    if size(slack, 2) == 1 % slack is a vector of weights
        slack = slack/sum(slack); % normalize weights
        v = H * slack;
        for k = 1:nbus
            H(:, k) = H(:, k) - v;
        end
    else
        H = H * slack;
    end
end
end

```

D.5 MATLAB PROGRAM FOR LODF CALCULATION

```

%-----LODF CALCULATION%-----

Cft1 = sparse([fb;tb], [1:nl 1:nl]', [ones(nl, 1); -ones(nl, 1)],
nbus, nl);
Z=zeros(nl,1);
PTDF1 = [H Z];
H1 = PTDF1 * Cft1;
h = diag(H1, 0);
LODF = H1 ./ (ones(nl, nl) - ones(nl, 1) * h');
LODF = LODF - diag(diag(LODF)) - eye(nl, nl);

```

D.6 MATLAB PROGRAM FOR BIALEK'S METHOD

```

%CALCULATION OF NODAL POWER
%-----
GenNum=[1 2 4 6 7];
LoadNum=[2 3 4 5 6 7];
PG = [300 50 0 200 0 150 90];
PL = [0 80 110 40 130 200 200];

for j=1:nbus

```



```

        E=0;
        for i=1:nbus
            if Plij(i,j)>=E;
                E=Plij(i,j)+E;
            end
        end
        Nod_Po(j)=E+PG(j);
    end
    disp(sprintf('\n Nodal active power in upstream'));E
    Nod_Po'

%CALCULATION OF UPSTREAM DISTRIBUTION MATRIX
for i=1:nbus
    for j=1:nbus
        if i == j
            Au(i,j)=1; %Upstream Looking Distribution Matrix
        elseif Plij(i,j)<0
            Au(i,j)=-Plij(j,i)/Nod_Po(j);
        else
            Au(i,j)=0;
        end
    end
end
disp(sprintf('\n\n Active Power'));
disp(sprintf('\n Active Power Line Flows:'));Plij
disp(sprintf('\n Upstream Looking Distribution Matrix:'));Au
IAu=inv(Au)
abs(Plij)
Nod_Po(j)
DG = (IAu/Nod_Po)*PLineForw(1:nl)

%TO CALCULATE CONTRIBUTION OF GENERATORS ON LINE FLOWS
disp(sprintf('\n\n Active Line Flows due to each Generator:'));
disp(sprintf('-----'));
disp(sprintf('Line No.\t From\t To \t MW Flow \t\t\t\t Due to'));
disp(sprintf('Gen-1\t\t Gen-2'));
disp(sprintf('-----'));
x=1;
for i=1:nbus
    for j=1:nbus
        if Plij(i,j)>0
            count=0;
            for k=GenNum
                MWflow(1,x)=Plij(i,j);
                count=count+1;
                Z(i,k) = IAu(i,k);
                M=(IAu(i,k))*PG(k);
                LineFlow(i,j)=(abs(Plij(i,j))/Nod_Po(i))*M;
                LineFlowPU(count)=LineFlow(i,j);
            end

disp(sprintf('\t%d\t%d\t%d\t%8.5f\t\t%8.5f',x,i,j,MWflow(1,x),LineFlowPU));

            x=x+1;
        end
    end
end
end
Z;

```

```

PG;
disp(sprintf('-----'));
% TO CALCULATE CONTRIBUTION GENERATORS ON LOADS
disp(sprintf('\nActive Power Load Demand:'));
disp(sprintf('-----
-'));
disp(sprintf('Load Generation Total'));
disp(sprintf(' G-1 G-2 Load '));
disp(sprintf('-----
-'));
for i=1:n
    if(PL(i)>0)
count=0;
for k=GenNum
count=count+1;
M(k)=(IAu(i,k))*PG(k);
LoadDemP(i) = (PL(i)/Nod_Po(i))*M(k) ;
LoadDemPU(count)=LoadDemP(i) ;
LoadSum=sum(LoadDemPU);
end
disp (sprintf ('%d \t      %3.3f \t      %3.3f \t
%3.3f',i,LoadDemPU,LoadSum));
end
end
disp(sprintf('-----
-'));
count=0;
for k=GenNum
count=count+1;
PGc(count)=PG(k);
end
disp(sprintf(' \t %3.3f \t %3.3f',PGc));
disp(sprintf('-----
-'));

%%%%%%%%%% DOWNSTREAM-LOOKING ALGORITHM %%%%%%%%%%
% CALCULATION OF NODAL POWER
for j=1:nbus
E=0;
for i=1:nbus
if Plij(i,j)<= E
E=-Plij(i,j) + E;
end
end
Nod_PoPD(j)=E+PL(j); % nodal power vector Pi
end
disp(sprintf('\n Nodal active power in downstream'));
Nod_PoPD'
% CALCULATION OF DOWNSTREAM DISTRIBUTION MATRIX
for i=1 :nbus
for j=1 :nbus
if(i == j)
Ad(i,j)=1; % Downstream Looking Distribution Matrix
elseif Plij(i,j)>=0
Ad(i,j)=Plij(j,i)/Nod_PoPD(j);
else
Ad(i,j)=0;
end
end
end

```

```

end
%disp(sprintf('Nodal Active Power in Downstream'));
disp(sprintf('\n Active Power Line Flow in Downstream:'));-Plij
disp(sprintf('\nDownstream Looking Distribution Matrix :'));
Ad
IAd=inv(Ad)
% TO CALCULATE CONTRIBUTION OF LOADS ON LINE FLOWS
disp(sprintf('\n\n Active Line flows to supply load demand:'));
disp(sprintf('-----
-----' ));
disp(sprintf('Line No. From To Line Flow\t\t\t\t\tSupplying'));
disp(sprintf('Load-3 Load-4'));
disp(sprintf('-----
-----' ));
x=1;
for i=1:nbus
for j=1:nbus
if (Plij(i,j) > 0)
count=0;
for k=LoadNum
MWflow(1,x)=Plij(i,j);
count=count+1 ;
M = (IAd(i,k))*PL(k);
LineflowP = (abs(Plij(i,j))/Nod_PoPD(i)) * M;
LineflowPD(count)=LineflowP ;
end
disp (sprintf ('\t%d \t %d \t %d \t\t%f \t\t\t %f \t\t\t %f'
,x,i,j, MWflow(1 ,x), LineflowPD)) ;
x=x+1;
end
end
end
disp(sprintf('-----
-----'));
PLineReve(1:nl)
DL = (IAd/Nod_PoPD)*abs(PLineReve(1:nl))

% TO CALCULATE CONTRIBUTION OF LOADS ON GENERATORS
disp(sprintf('\nActive Generation Output to supply each Load Demand:
'))
disp(sprintf('-----
-'));
disp(sprintf('\t\t\t Generation Gen Output To supply '))
disp(sprintf(' Load Demand '))
disp(sprintf('-----
-'));
for i=1:nbus
for k=LoadNum
if(PG(i)>0)
X(k)=(IAd(i,k))*PL(k);
GenNodeD = (PG(i)/Nod_PoPD(i)) * X(k) ;
disp (sprintf ('Gen-%d \t\t%f \t\t %f \t\t\t\t\t %d
',i,PG(i),GenNodeD, k));
end
end
end

```

D.7 MATLAB PROGRAM FOR CONGESTION COST CALCULATION

```
%-----
%2.CALCULATION OF CONGESTION COSTS

PGen= [277.3 46.2 0 200 0 149.8 86.7]; % Generation Unconstrained
Case
PGen1=[184.3 121.1 0 110.0 0 220.0 124]; % Generation Constrained
Case
%PGen1=[69 166.2 0 154.8 0 242.0 128]; % Generation Constrained Case
PLoad=[0 80 110 40 130 200 200]; % Load Demand
% CALCULATION OF GENRATOR PRODUCTION COSTS IN
% (UNCONSTRAINED CASE)
PC(1)=0.0020*(PGen(1))^2 + 8.50*PGen(1) + 300;
PC(2)=0.0014*(PGen(2))^2 + 9.48*PGen(2) + 420;
PC(3)=0.0013*(PGen(4))^2 + 7.29*PGen(4) + 253;
PC(4)=0.0013*(PGen(6))^2 + 9.22*PGen(6) + 380;
PC(5)=0.0019*(PGen(7))^2 + 9.28*PGen(7) + 380;
disp(sprintf('\n\n GENERATOR COST FUNCTIONS(NO CONSTRAINTS)'));
for k=1:5
disp(sprintf('\t Gen-%d : %5.3f \t %5.3f \t %5.3f \t %5.3f \t
%5.3f',k,PC(k)));
end
% CALCULATION OF GENRATOR PRODUCTION COSTS IN
% (CONSTRAINED CASE )
PC1(1)=0.0020*(PGen1(1))^2 + 8.50*PGen1(1) + 300;
PC1(2)=0.0014*(PGen1(2))^2 + 9.48*PGen1(2) + 420;
PC1(3)=0.0013*(PGen1(4))^2 + 7.29*PGen1(4) + 253;
PC1(4)=0.0013*(PGen1(6))^2 + 9.22*PGen1(6) + 380;
PC1(5)=0.0019*(PGen1(7))^2 + 9.28*PGen1(7) + 380;
disp(sprintf('\n GENERATOR COST FUNCTIONS(WITH CONSTRAINT):'));
for k=1:5
disp(sprintf('\t Gen-%d : %5.3f \t %5.3f \t %5.3f \t %5.3f \t
%5.3f',k,PC1(k)));
end
TCC = (PC1-PC)
% Load Contributions
D = [ 30.9024 45.8528 1.7445 37.4139 9.8638 9.2226;
      0.0000 12.9032 12.9032 12.0520 0.0000 2.1415;
      0.0000 14.1935 14.1935 13.2572 0.0000 2.3557];
% Load Contributions
%%% Change in Line Flows
Delta_flow= [91.5 27.1 29.9];
%%% Change in Production Costs
RC=[92.36 38.06 103.57];
for i=1:3
O(i) = RC(i)*Delta_flow(i);
end
% Calculation of constraint allocation cost
for i=1:3
k=1:5;
ST = sum(TCC(:,k));
TC(i) = (O(i)*ST)/(sum(O)) ;
end
%end
% CALCULATION OF CONGESTION COSTS
for i = 1:3
for k = 1:6
```

```

SD(i)= sum(D(i,:));
CC(i,k)= D(i,k)*TC(i)/SD(i);
CongCost(k)=sum(CC(:,k)) ;
ToT_Con = sum(CongCost);
end
end
disp(sprintf('\n\n Congestion Cost'));
disp(sprintf('-----
----- '));
disp(sprintf(' Load-2 \t\t Load-3 \t\t Load-4 \t\t Load-5 \t\t Load-
6 \t\t Load-7 \t\t Total'));
disp(sprintf(' %4.4f \t\t %4.4f \t\t', CongCost,ToT_Con));
% RESULTS IN EXCEL FILE
%resultsfilename='F:\Volume F\Amit Thesis Load
Flow\Bus30\Unconstrained\30Bus load flow calcu UN.xlsx';
%results
%xlswrite(resultsfilename,{'FROM'},1,'a2:a2')
%xlswrite(resultsfilename,bus,1,'a3')
%xlswrite(resultsfilename,V,1,'b3')
%xlswrite(resultsfilename,Del,1,'c3')
%xlswrite(resultsfilename,Pi,1,'d3')
%xlswrite(resultsfilename,Qi,1,'e3')
%xlswrite(resultsfilename,Pg,1,'f3')
%xlswrite(resultsfilename,Qg,1,'g3')
%xlswrite(resultsfilename,Pl,1,'h3')
%xlswrite(resultsfilename,Ql,1,'i3')
%xlswrite(resultsfilename,fb,1,'b15')
%xlswrite(resultsfilename,tb,1,'c15')
%xlswrite(resultsfilename,H,1,'d15')
%xlswrite(resultsfilename,fb,2,'b4')
%xlswrite(resultsfilename,tb,2,'c4')
%xlswrite(resultsfilename,LODF,2,'d4')
%xlswrite(resultsfilename,fb',3,'d2')
%xlswrite(resultsfilename,tb',3,'d3')
%xlswrite(resultsfilename,Nod_Po',3,'b4')
%xlswrite(resultsfilename,Au,3,'d4')
%xlswrite(resultsfilename,DG,3,'m4')
%xlswrite(resultsfilename,fb,1,'k3')
%xlswrite(resultsfilename,tb,1,'l3')
%xlswrite(resultsfilename,PlineForwI,1,'m3')
%xlswrite(resultsfilename,QlineForwI,1,'n3')
%xlswrite(resultsfilename,tb,1,'o3')
%xlswrite(resultsfilename,fb,1,'p3')
%xlswrite(resultsfilename,PlineReveI,1,'q3')
%xlswrite(resultsfilename,QlineReveI,1,'r3')
%xlswrite(resultsfilename,Lpij,1,'s3')
%xlswrite(resultsfilename,Lqij,1,'t3')
%xlswrite(resultsfilename,PlineI,1,'k3')
%xlswrite(resultsfilename,Lpij,1,'l3')
%xlswrite(resultsfilename,Nod_Po,2,'b3')
%xlswrite(resultsfilename,Au,2,'b5')
%xlswrite(resultsfilename,IAu,2,'j5')
%xlswrite(resultsfilename,Ad,4,'d4')
%xlswrite(resultsfilename,IAAd,3,'l4')
%xlswrite(resultsfilename,PC',7,'b22')
%xlswrite(resultsfilename,PC1',7,'e22')
%xlswrite(resultsfilename,TCC',7,'g3')
%xlswrite(resultsfilename,CongCost',7,'i3')
%xlswrite(resultsfilename,ToT_Con,7,'k3')

```

D.8 MATLAB PROGRAM FOR TRANSMISSION PRICING USING MW MILE METHOD

```
%
%
%TRANSMISSION PRICING BY REVERSE MW MILE METHOD
%
%

for m = 1:nl
%for j = 1:nl
    p = fb(m); q = tb(m);

    if          Plij(fb(m),tb(m)) < 0

    end

    %Plij(q,p) = 0;
    TrPR(m) = (LN(m)*CP(m)*(Plij(fb(m),tb(m))))/((LT(m))*8760);
    ToT_TrPR = sum(TrPR);
end

disp(sprintf('\n\n Transmission price REVERSE MW mile'));
disp(sprintf('-----'));
disp(sprintf(' %4.4f \t\t %4.4f \t\t',TrPR,ToT_TrPR));
%
%TRANSMISSION PRICING BY ABSOLUTE MW MILE METHOD
%
for m = 1:nl
%for j = 1:nl
    p = fb(m); q = tb(m);

    if          Plij(fb(m),tb(m)) < 0

    end

    %Plij(q,p) = 0;
    TrPA(m) =
(LN(m)*CP(m)*abs(Plij(fb(m),tb(m))))/((LT(m))*8760);
    ToT_TrPA = sum(TrPA);
end

disp(sprintf('\n\n Transmission price ABSOLUTE MW mile'));
disp(sprintf('-----'));
disp(sprintf(' %4.4f \t\t %4.4f \t\t',TrPA,ToT_TrPA));
%
%TRANSMISSION PRICING BY DOMINANT MW MILE METHOD
%
for m = 1:nl
%for j = 1:nl
    p = fb(m); q = tb(m);

    if          Plij(fb(m),tb(m)) < 0
        Plij(fb(m),tb(m)) = 0;
    end
    TrPD(m) = (LN(m)*CP(m)*Plij(fb(m),tb(m)))/((LT(m))*8760);
```

```

        ToT_TrPD = sum(TrPD);
    end

disp(sprintf('\n\n Transmission price DOMINANT MW mile'));
disp(sprintf('----- '));
disp(sprintf(' %4.4f \t\t %4.4f \t\t',TrPD,ToT_TrPD));

%resultsfilename='F:\Volume F\Amit Thesis Load Flow\Bus
7\Unconstrained\TransPrice7.xlsx';
%col_header={resultsfilename,'AMIT',1,'a2'} % making columns in the
Matlab
%results
%col_header={'AMIT'}
%OT={'AMIT'};
%xlswrite(resultsfilename,TrPR,1,'a3')
%xlswrite(resultsfilename,ToT_TrPR,1,'a5')
%xlswrite(resultsfilename,TrPA,1,'a7')
%xlswrite(resultsfilename,ToT_TrPA,1,'a9')
%xlswrite(resultsfilename,TrPD,1,'a11')
%xlswrite(resultsfilename,ToT_TrPD,1,'a13')

```

D.9 CAPACITY OUTAGE PROBABILITY TABLE MATLAB PROGRAM

```

clc
clear all
Peak=220;
yload=[1 0;2 80;3 110;4 40;5 130;6 200;7 200];
ny=size(yload,1);
%nw=size(wload,1);
%nd=size(dload,1);
yload(:,2)=yload(:,2);
%wload(:,2)=wload(:,2)/100;
%dload(:,2)=dload(:,2)/100;
t=0;
for i=1:ny
%for j=1:nw
%for k=1:nd
for t=t+1;
LDCload(t,1)=yload(i,2);%*wload(j,2)*dload(k,2);
end
end
%end
%end
LDCload=sortrows(LDCload*Peak,-1);
LDCload=LDCload';
n=1:t;
LDCld=(LDCload-mean(LDCload))./std(LDCload);
Coef=polyfit(LDCld,n,4);
% % fit=Coef(1)*x.^4+Coef(2)*x.^3+Coef(3)*x.^2+Coef(4)*x+Coef(5);
f=polyval(Coef,LDCld);
plot(LDCld,n,'r-',LDCld,f,'-b')
legend('LDC Curve','Fitted Curve')
grid on
figure(2)
plot(n,LDCld,'k-')
grid on

```

D.10 MONTE CARLO VARIANCE REDUCTION TECHNIQUE MATLAB PROGRAM FOR DETERMINING EENS

D.10.1 SIMPLE SAMPLING

```

clc
dbstop if error
tic
clear all
format short
%-----
%General data for RBTS
%-----
NrNodes = 7;
RefNode = 1; %in this node the angle is 0
NrLines = 10;
NrGen = 5;
NrLP = 6;
Gen_LP_Node = [1 1 1 1 1 2 2 2 2 2 2];
LPGen = [zeros(1,5) ones(1,6)];
Gen_LP_Cost = [10.5 11.5 10.7 11.23 12.48 8000 11000 4000 13000
20000 20000];
LineDef = [1 2; 1 3; 2 3; 2 4; 2 5; 2 6; 3 4; 4 5; 7 5; 6 7];
%Per unit base
Sbase = 100; %MVA
Ubase = 230; %kV
%Line reaktances (in ohm per line)
%L1 - L9 , here in pu
XLines_temp_pu = [0.06; 0.24; 0.18; 0.18; 0.12; 0.06; 0.03; 0.24;
0.06; 0.24];
%Convert to in ohm per line)
Zb = Ubase^2/Sbase;
XLines = XLines_temp_pu*Zb;
%Generator- or load-nodes, max and min active power (MW)
Gen_LP_MaxP = [300; 50; 200; 150; 90; 0; 0; 0; 0; 0; 0];
Gen_LP_MinP = [ 0; 0; 0; 0; 0; -80; -110; -40; -130; -200; -200];
%Line max and min active power capacity (MW)
LineMaxP = [135; 58; 55; 45; 200; 130; 40; 44; 100; 85];
LineMinP = -LineMaxP;
%Reliability data
%Forced outage rate in, (Unavailability over the year)
%for the generators (bot Gen and LP) and lines
lambda = [6 4 6 5 3 -1*ones(1,6) 1.5 1 5 1 1.5 1 1 1.5 1 1.5];
r = [ 45 45 45 60 55 zeros(1,6) 10 10 10 10 10 10 10 10 10 10];
FOR_comp = (lambda.*r)./(8760+(lambda.*r));
%-----
%End of system data
%-----
%-----
%Simulation data
%-----
%Minimum simulations
min_nr_sim = 40;
%Minimum coefficient of variance
aY_min = 1.0;
%Number of samples per batch (per sim)
nr_samples = 10000;
hours_per_year = 8760;

```



```

%-----
%End of simulation data
%-----
disp(' ')
disp(' ')
disp('*****')
disp('-----')
disp(' RBTS MCS- VRT Simple Sampling ')
disp('-----')
disp('*****')
disp(' ')
disp('General system load flow:')
%Run one intact system load flow (all comp ok)
CompStatus = [1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1];
[angNodes, P_Unit, P_LP_Node, P_Gen_Node, LineFlows, Shed_P,
exitflag] = DC_loadflowVer3(NrNodes, RefNode, NrLines, Gen_LP_Node,
LPGen, NrGen, NrLP, Gen_LP_Cost, LineDef, XLines, Sbase, Ubase,
Gen_LP_MaxP, Gen_LP_MinP, LineMaxP, LineMinP, CompStatus)
disp('exitflag:')
disp(exitflag)
if sum(Shed_P)>0
disp('Intact system setup has load curtailments: (MW)');
disp(Shed_P);
else
disp('General load flow of system is OK. No load shed.')
end
disp(' ')
%Set a new random state
rand('state', sum(100*clock))
%Error control
error_vec=[];
error_state_vec=[];
%Data vectors
Nr_Curtailments_LP_vec = [];
PLC_vec=[];
PLC_LP_vec=[];
EDNS_vec=[];
EDNS_LP_vec=[];
EENS_vec=[];
EENS_LP_vec=[];
var_EENS_vec = [];
aY_vec = [];
temp = [];
nr_sim=0;
aY=0;
%Start Sim
while ((nr_sim<min_nr_sim) || (aY>aY_min))
nr_sim = nr_sim + 1;
%New data vectors
Total_Shed_LP_P = zeros(1,NrLP);
Nr_Curtailments_LP = zeros(1,NrLP);
%Keep record of errors
error=0;
for n=1:nr_samples

%-----
%Step 1, select system state x
%-----
%1a Generate uniform random numbers for the components

```

```

random_numbers = rand(1,NrGen+NrLP+NrLines);
%1b Compare these with the define values, if the generated values
are
%less - > give the component a 0 (down), else 1 (up)
CompStatus = (random_numbers > FOR_comp)';
%-----
%Step 2, Calculate F(x) for the selected state
%-----
%Skip DC load flow if system intact (we know that no load is shed)
if (sum(CompStatus)<(NrGen+NrLP+NrLines))
%Use DC_loadflow to check if this state means any load curtailments
[angNodes, P_Unit, P_LP_Node, P_Gen_Node, LineFlows, Shed_P,
exitflag] = DC_loadflowVer3(NrNodes, RefNode, NrLines, Gen_LP_Node,
LPGen, NrGen, NrLP, Gen_LP_Cost, LineDef, XLines, Sbase, Ubase,
Gen_LP_MaxP, Gen_LP_MinP, LineMaxP, LineMinP, CompStatus);
else
exitflag = 1;
Shed_P = 0;
end
%ERROR Control
%Keep control of the errors (no convergence)
if (exitflag ~= 1)
error=error+1;
%Only check lines first
error_state_vec=[error_state_vec; CompStatus(22:30)'];
end
%-----
%Step 3, Update the estimates
%-----
%Only required if there is a load curtailment
if sum(Shed_P)>0
%Update curtailment energy (Shed_P is a vector for each LP)
Total_Shed_LP_P = Total_Shed_LP_P + Shed_P';
%Update curtailments per LP
Nr_Curtailments_LP = Nr_Curtailments_LP + (Shed_P'>0);
if Shed_P(2)>0
temp = [temp; CompStatus'];
end
end
end %end sample
%Total nr of curtailments
Nr_Curtailments_LP_vec = [Nr_Curtailments_LP_vec;
Nr_Curtailments_LP];
%PLC = Probability of load curtailment
%First per LP
PLC_LP_sample = Nr_Curtailments_LP/nr_samples;
PLC_LP_vec=[PLC_LP_vec; PLC_LP_sample];
%Then total system
PLC_sample = sum(Nr_Curtailments_LP)/nr_samples;
PLC_vec=[PLC_vec; PLC_sample];
%EDNS = Expected demand not supplied (MW)
%First per LP
EDNS_LP_sample = Total_Shed_LP_P/nr_samples;
EDNS_LP_vec=[EDNS_LP_vec; EDNS_LP_sample];
%Then total system
EDNS_sample = sum(Total_Shed_LP_P)/nr_samples;
EDNS_vec=[EDNS_vec; EDNS_sample];
%EENS
EENS_sample = EDNS_sample*hours_per_year;

```

```

EENS_vec=[EENS_vec; EENS_sample];
EENS_LP_vec=[EENS_LP_vec; EDNS_LP_sample*hours_per_year];
%variation of EENS until this sim
var_EENS_estimate = (1/nr_sim)*sum(EENS_vec.^2)-
((1/nr_sim)*sum(EENS_vec))^2;
var_EENS_vec = [var_EENS_vec; var_EENS_estimate];
aY = sqrt(var_EENS_estimate)/((1/nr_sim)*sum(EENS_vec)
*sqrt(nr_sim));
aY_vec =[aY_vec; aY];
>Error control
error_vec = [error_vec; error];
disp('---')
disp('Simulation:')
disp(nr_sim)
disp('EENS:')
disp(EENS_sample)
disp('sigma[EENS]:')
disp(sqrt(var_EENS_estimate))
disp('Var[EENS]:')
disp(var_EENS_estimate)
disp('Coefficient of variance:')
disp(aY)
disp('---')
end %end sim
%PLC estimate
%First per LP
PLC_LP_estimate = sum(PLC_LP_vec)/nr_sim;
%Then total system
PLC_estimate = sum(PLC_vec)/nr_sim;
%EDNS estimate
%First per LP
EDNS_LP_estimate = sum(EDNS_LP_vec,1)/nr_sim;
%Then total system
EDNS_estimate = sum(EDNS_vec)/nr_sim;
%EENS estimate (Expected Energy not supplied)
%First per LP
EENS_LP_estimate = sum(EENS_LP_vec,1)/nr_sim;
%Then total system
EENS_estimate = sum(EENS_vec)/nr_sim;
disp('Nr of curtailments per LP:')
disp(Nr_Curtailments_LP_vec)
disp('PLC (Probability of load curtailment), For each load point
LP2-LP6:')
fprintf(1,'%10.5f\n',PLC_LP_estimate);
disp('PLC (Probability of load curtailment), Total System:')
fprintf(1,'%10.5f\n',PLC_estimate);
disp('EDNS (Expected demand not supplied) [MW], For each load point
LP2-LP6:')
fprintf(1,'%10.5f\n',EDNS_LP_estimate);
disp('EDNS (Expected demand not supplied) [MW], Total System:')
fprintf(1,'%10.5f\n',EDNS_estimate);
disp('EENS (Expected energy not supplied) [MWh/yr], For each load
point LP2-LP6:')
fprintf(1,'%10.5f\n',EENS_LP_estimate);
disp('EENS (Expected energy not supplied) [MWh/yr], Total System:')
fprintf(1,'%10.5f\n',EENS_estimate);
disp('min EENS sample:')
fprintf(1,'%10.5f\n',min(EENS_vec));
disp('max EENS sample:')

```

```

fprintf(1,'%10.5f\n',max(EENS_vec));
disp('Var[EENS] (Variance of EENS), For all samples, after
Simulation i:')
fprintf(1,'%10.2f\n',var_EENS_vec);
disp('Coefficient of Variance, based on EENS:')
fprintf(1,'%10.4f\n',aY_vec);
plot(1:nr_sim, aY_vec)
%Error Control
if(sum(error_vec)>0)
disp('-----')
disp('*****')
disp('One or more errors in DC load flow!')
disp('*****')
disp('-----')
end
disp('Total nr of samples:')
disp(nr_sim*nr_samples);
disp('Total simulation time: (h:min:s)')
sim_time = toc;
nr_hours = floor(sim_time/3600);
nr_minutes = floor((sim_time-nr_hours*3600)/60);
nr_seconds = ceil(sim_time-nr_hours*3600-nr_minutes*60);
fprintf(1,'%2.0f:%2.0f:%2.0f\n',nr_hours,nr_minutes,nr_seconds);
disp('-----')
disp('The End')
disp('-----')

```

D.10.2 IMPORTANCE SAMPLING

```

tic
clear all
format short
%-----
% Data for RBTS
%-----
NrNodes = 7;
RefNode = 1; %in this node the angle is 0
NrLines = 10;
NrGen = 5;
NrLP = 6;
Gen_LP_Node = [1 1 1 1 1 2 2 2 2 2];
LPGen = [zeros(1,5) ones(1,6)];
Gen_LP_Cost = [10.5 11.5 10.7 11.23 12.48 8000 11000 4000 13000
20000 20000];
LineDef = [1 2; 1 3; 2 3; 2 4; 2 5; 2 6; 3 4; 4 5; 7 5; 6 7];
%Per unit base
Sbase = 100; %MVA
Ubase = 230; %kV
%Line reaktances (in ohm per line)
%L1 - L9 , here in pu
XLines_temp_pu = [0.06; 0.24; 0.18; 0.18; 0.12; 0.06; 0.03; 0.24;
0.06; 0.24];
Zb = Ubase^2/Sbase;
XLines = XLines_temp_pu*Zb;
%Generator- or load-nodes, max and min active power (MW)
Gen_LP_MaxP = [300; 50; 200; 150; 90; 0; 0; 0; 0; 0];
Gen_LP_MinP = [0; 0; 0; 0; 0; -80; -110; -40; -130; -200];
%Line max and min active power capacity (MW)
LineMaxP = [135; 58; 55; 45; 200; 130; 40; 44; 100; 85];

```

```

LineMinP = -LineMaxP;
%Forced outage rate in, (Unavailability over the year)
%for the generators (bot Gen and LP) and lines
lambda = [6 4 6 5 3 -1*ones(1,6) 1.5 1 5 1 1.5 1 1 1.5 1 1.5];
r = [ 45 45 45 60 55 zeros(1,6) 10 10 10 10 10 10 10 10 10];
%FOR_comp = (lambda.*r)/8760
FOR_comp = (lambda.*r)./(8760+(lambda.*r));
%-----
%End of system data
%-----
%Simulation data
%-----
%Minimum simulations
min_nr_sim = 40;
%Minimum coefficient of variance
aY_min = 1.0;
%Number of samples per batch (per sim)
nr_samples = 10000;
hours_per_year = 8760;
%-----
%End of simulation data
%-----
disp(' ')
disp(' ')
disp('*****')
disp('-----')
disp(' RBTS MCS (Lines and Generators can fail)')
disp('-----')
disp('***** Importance Sampling *****')
disp(' ')
disp('General system load flow:')
%Run one intact system load flow (all comp ok)
CompStatus = [1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1];
[angNodes, P_Unit, P_LP_Node, P_Gen_Node, LineFlows, Shed_P,
exitflag] = DC_loadflowVer3(NrNodes, RefNode, NrLines, Gen_LP_Node,
LPGen, NrGen, NrLP, Gen_LP_Cost, LineDef, XLines, Sbase, Ubase,
Gen_LP_MaxP, Gen_LP_MinP, LineMaxP, LineMinP, CompStatus);
disp('exitflag:')
disp(exitflag)
if sum(Shed_P)>0
disp('Intact system setup has load curtailments: (MW)');
disp(Shed_P);
else
disp('General load flow of system is OK. No load shed.')
end
%Set a new random state
rand('state', sum(100*clock))
%Error control
error_vec=[];
error_state_vec=[];
%Data vectors
Nr_Curtailments_LP_vec = [];
PLC_vec=[];
PLC_LP_vec=[];
EDNS_vec=[];
EDNS_LP_vec=[];
EENS_vec=[];
EENS_LP_vec=[];
var_EENS_vec = [];

```

```

aY_vec = [];
temp = [];
nr_sim=0;
aY=0;
FOR_comp_z = [0.15*ones(1,5) zeros(1,6) 0.15*ones(1,10)];
%Start Sim
while ((nr_sim<min_nr_sim) || (aY>aY_min))
nr_sim = nr_sim + 1;
%New data vectors
Total_Shed_LP_P = zeros(1,NrLP);
Nr_Curtailments_LP = zeros(1,NrLP);
%Keep record of errors
error=0;
sum_x_h = 0;
%w_i_all_samples = [];
for n=1:nr_samples
%-----
%Step 1, select system state x
%-----
%1a Generate uniform random numbers for the components
random_numbers = rand(1,NrGen+NrLP+NrLines);
%1b Compare these with the define values, if the generated values
are
%less - > give the component a 0 (down), else 1 (up)
%OBS importance sampling
CompStatus = (random_numbers > FOR_comp_z)';
%%%%%%%%%%%%
%Determine weights
fy=1;
fz=1;
for k=1:length(CompStatus)
fy = fy*(CompStatus(k)*(1-FOR_comp(k)) + (1-
CompStatus(k))*FOR_comp(k));
fz = fz*(CompStatus(k)*(1-FOR_comp_z(k)) + (1-
CompStatus(k))*FOR_comp_z(k));
end
w_i = fy/fz;
%w_i_all_samples = [w_i_all_samples; fy/fz];
%-----
%Step 2, Calculate F(x) for the selected state
%-----
%Skip DC load flow if system intact (we know that no load is shed)
if (sum(CompStatus)<(NrGen+NrLP+NrLines))
%Use DC_loadflow to check if this state means any load curtailments
[angNodes, P_Unit, P_LP_Node, P_Gen_Node, LineFlows, Shed_P,
exitflag] = DC_loadflowVer3(NrNodes, RefNode, NrLines, Gen_LP_Node,
LPGen, NrGen, NrLP, Gen_LP_Cost, LineDef, XLines, Sbase, Ubase,
Gen_LP_MaxP, Gen_LP_MinP, LineMaxP, LineMinP, CompStatus);
else
exitflag = 1;
Shed_P = 0;
end
%ERROR Control
%Keep control of the errors (no convergence)
if (exitflag ~= 1)
error=error+1;
%Only check lines first
error_state_vec=[error_state_vec; CompStatus(22:30)'];
end

```

```

%-----
%Step 3, Update the estimates
%-----
%Include weight w_i
sum_x_h = sum_x_h + w_i*sum(Shed_P)*hours_per_year;
end %end sample
%Multiply with the stratum weights w_i
EENS_sample = sum_x_h/nr_samples;
%EENS
EENS_vec=[EENS_vec; EENS_sample];
%variation of EENS until this sim
var_EENS_estimate = (1/nr_sim)*sum(EENS_vec.^2)-
((1/nr_sim)*sum(EENS_vec))^2;
var_EENS_vec = [var_EENS_vec; var_EENS_estimate];
%var_mY =
aY =
sqrt(var_EENS_estimate)/((1/nr_sim)*sum(EENS_vec)*sqrt(nr_sim));
aY_vec =[aY_vec; aY];
%Error control
error_vec = [error_vec; error];
disp('---')
disp('Simulation:')
disp(nr_sim)
disp('EENS:')
disp(EENS_sample)
disp('sigma[EENS]:')
disp(sqrt(var_EENS_estimate))
disp('Var[EENS]:')
disp(var_EENS_estimate)
disp('Coefficient of variance:')
disp(aY)
disp('---')
end %end sim
%EENS estimate (Expected Energy not supplied)
%Then total system
EENS_estimate = sum(EENS_vec)/nr_sim;
disp('EENS (Expected energy not supplied) [MWh/yr], Total System:')
fprintf(1,'%10.5f\n',EENS_estimate);
disp('min EENS sample:')
fprintf(1,'%10.5f\n',min(EENS_vec));
disp('max EENS sample:')
fprintf(1,'%10.5f\n',max(EENS_vec));
disp('Var[EENS] (Variance of EENS), For all samples, after
Simulation i:')
fprintf(1,'%10.2f\n',var_EENS_vec);
disp('sigma[EENS]:')
disp(sqrt(var_EENS_vec(length(var_EENS_vec))))
disp('Coefficient of Variance, based on EENS:')
fprintf(1,'%10.4f\n',aY_vec);
plot(1:nr_sim, aY_vec)
%Error Control
if(sum(error_vec)>0)
disp('-----')
disp('*****')
disp('One or more errors in DC load flow!')
disp('*****')
disp('-----')
end
disp('Total nr of samples:')

```

```

disp(nr_sim*nr_samples);
disp('Total simulation time: (h:min:s)')
sim_time = toc;
nr_hours = floor(sim_time/3600);
nr_minutes = floor((sim_time-nr_hours*3600)/60);
nr_seconds = ceil(sim_time-nr_hours*3600-nr_minutes*60);
fprintf(1,'%2.0f:%2.0f:%2.0f\n',nr_hours,nr_minutes,nr_seconds);
disp('-----')
disp('The End')
disp('-----')

```

D.11 MATLAB PROGRAM FOR CUSTOMER DAMAGE FUNCTION AND DETERMINING ECOST

```

clear all
tic
v=0; h=0; e = 0;
for i = 1:50
FLA = 0; unavailLLA = 0; ecost=0;
rand( 'state', sum(100*clock));
for N=1:5000;
t1=0;td1=0; t2=0;td2=0; t6=0;td6=0; t7=0;td7=0;
c1=0;c2=0;
c6=0;c7=0;
l1=0.065/8760;l2=0.091/8760;
l6=0.006/8760;l7=0.015/8760;
t = 0;
a1=rand; a2=rand;
a6=rand; a7=rand;
T1=(-1/l1)* reallog(a1);
T2=(-1/l2)* reallog(a2);
T6=(-1/l6)* reallog(a6);
T7=(-1/l7)* reallog(a7);
y = [T1,T2,T6,T7];
x = min(y);
while x < 8760
t=0;
t= t + x;
if x == y(1,1)
Tr1 = lognrnd(1.60944,(0)^2);
t1 = t1 + 1;
td1 = td1 + Tr1;
c1 = c1 + (0.74 + (0.67)*(Tr1 - 4));
a1 = rand ;
T1=(-1/l1)* reallog(a1);
t = t + Tr1 + T1;
T1 = t;
y = [T1,T2,T6,T7];
x = min(y);
elseif x == y(1,2)
Tr2 = lognrnd(1.60944,(0)^2);
t2 = t2 + 1;
td2 = td2 + Tr2;
c2 = c2 + (0.74 + (0.67)*(Tr2 - 4));
a2 = rand;
T2=(-1/l2)* reallog(a2);
t = t + Tr2 + T2;

```



```

T2= t;
y = [T1,T2,T6,T7];
x = min(y);
elseif x == y(1,3)
Tr6 = lognrnd(1.386294,(0.4)^2);
t6 = t6 + 1;
td6 = td6 + Tr6;
c6 = c6 + (0.74 + (0.67)*(Tr6 - 4));
a6 = rand;
T6=(-1/16)* reallog(a6);
t = t + Tr6+T6;
T6=t;
y = [T1,T2,T6,T7];
x = min(y);
elseif x == y(1,4)
Tr7 = lognrnd(2.302585,(0)^2);
t7 = t7 + 1;
td7 = td7 + Tr7;
c7 = c7 + (0.74 + (0.67)*(Tr7 - 4));
a7 = rand;
T7=(-1/17)* reallog(a7);
t = t + Tr7 + T7;
T7=t;
y = [T1,T2,T6,T7];
x = min(y);
end
end
% failure rate
fLA= (t1 + t2 + t6 + t7);
FLA= FLA + fLA;
% unavailability
unavaiLLA = ((t1).* td1 )+ ((t2).* td2) + ((t6).* td6) +
((t7).*td7);
unavaiLLA= unavaiLLA + unavaiLLA;
cost = c1 + c2 + c6 + c7;
ecost = ecost + cost;
end
v= v + FLA/N;
h = h + unavaiLLA/N;
e = e + ecost/N;
end
d=1:10;
g = v/(i);
k(d,:)= h/(i);
m(d,:)= (e/(i));
z(d,:) = (h/(i)) ;
%end
g ;
k ;
mean(m)* 33000 ;
mean(z)* 33000 ;
disp('-----');
disp('ECOST ');
disp('-----');
fprintf('\n %4g  \n', e)
toc

```

APPENDIX-E

E.1 CONTENTS OF ENCLOSED CD

There is a CD enclosed to this thesis which contains the following Data.

1. Power Injected, Voltage and Phase angle for IEEE 30-Bus (Constrained case)
2. Line Flow and Line Loss for IEEE 30-Bus (Constrained case)
3. Power Injected, Voltage and Phase angle for Indian Utility 146-Bus (Unconstrained and Constrained case)
4. Line Flow and Line Loss for Indian Utility 146-Bus (Unconstrained and Constrained case)
5. Transmission pricing results in table format for all 3 test systems.
6. PTDF, GGDF and GLDF for 30-Bus system
7. Load and generator contribution using PTDF and Bialek's method for 30-Bus system.
8. Transmission charges using generator contribution (Bialek's and PTDF method) for 30 –Bus system
9. PTDF, GGDF and GLDF for 146-Bus system
10. Load and generator contribution using PTDF and Bialek's method for 146-Bus system.
11. Transmission charges using generator contribution (Bialek's and PTDF method) for 146 –Bus system
12. The probability of load curtailments and EDNS for every load of 146-Bus system.

13. The generator's and load's contributions on line flow and each other using Bialek's method shown in bar chart in Figure 6.13, Figure 6.14, Figure 6.15 and Figure 6.16, the tables are provided in Appendix. E (CD attached).